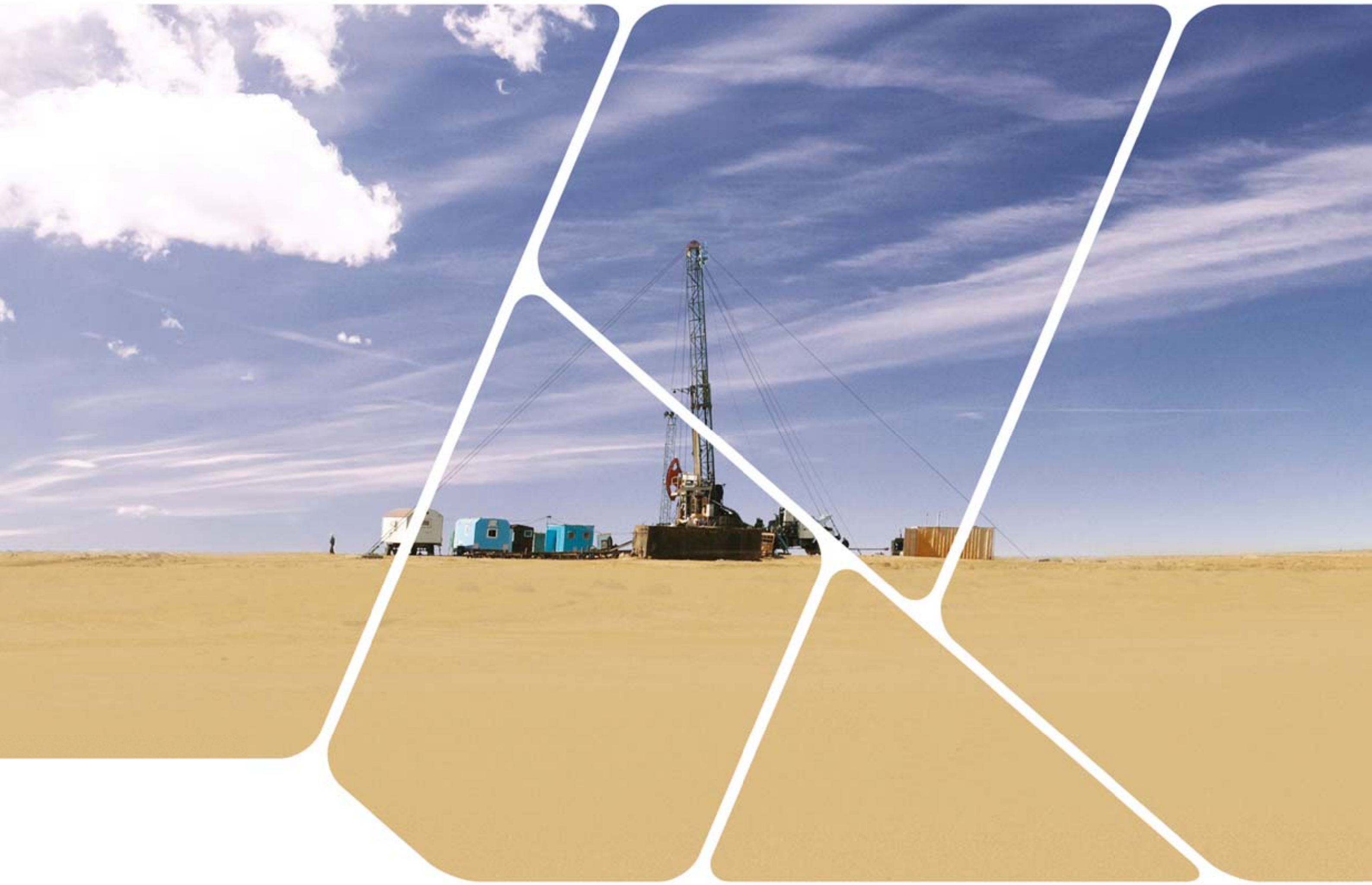


RESERVOIR ENGINEERING GRADUATE CERTIFICATE - *Week 5*

Drilling & completion - Well Productivity & Reservoir-Wellbore Interface

A special course by IFP Training for REPSOL ALGERIA
Alger – November 27 – December 01, 2016

ifptraining.com

An IFP Training Course for REPSOL

Drilling/Completion for Reservoir Studies

Instructor: Tammam Hammad

Contents

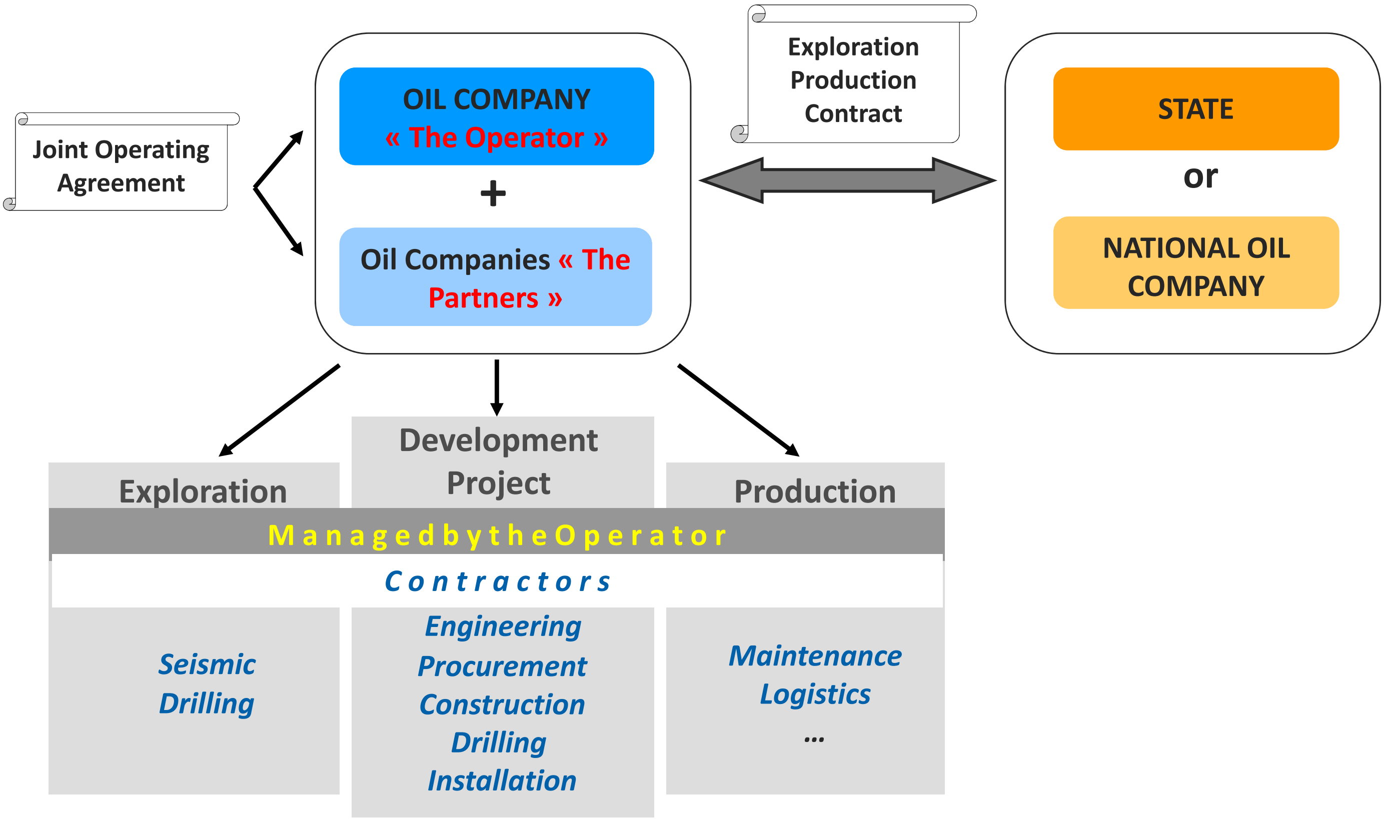
Drilling – Introduction

Drilling introduction

- In Exploration, drilling a well is the only method to prove the existence of hydrocarbons following a seismic survey
- The objective is to provide a maximum of technical information to minimize uncertainties to develop (or not) an oil deposit

- In Development, after the evaluation of the “reserves” and economic studies (including CAPEX & OPEX), the objective is to produce i.e. to provide good producer or injector wells

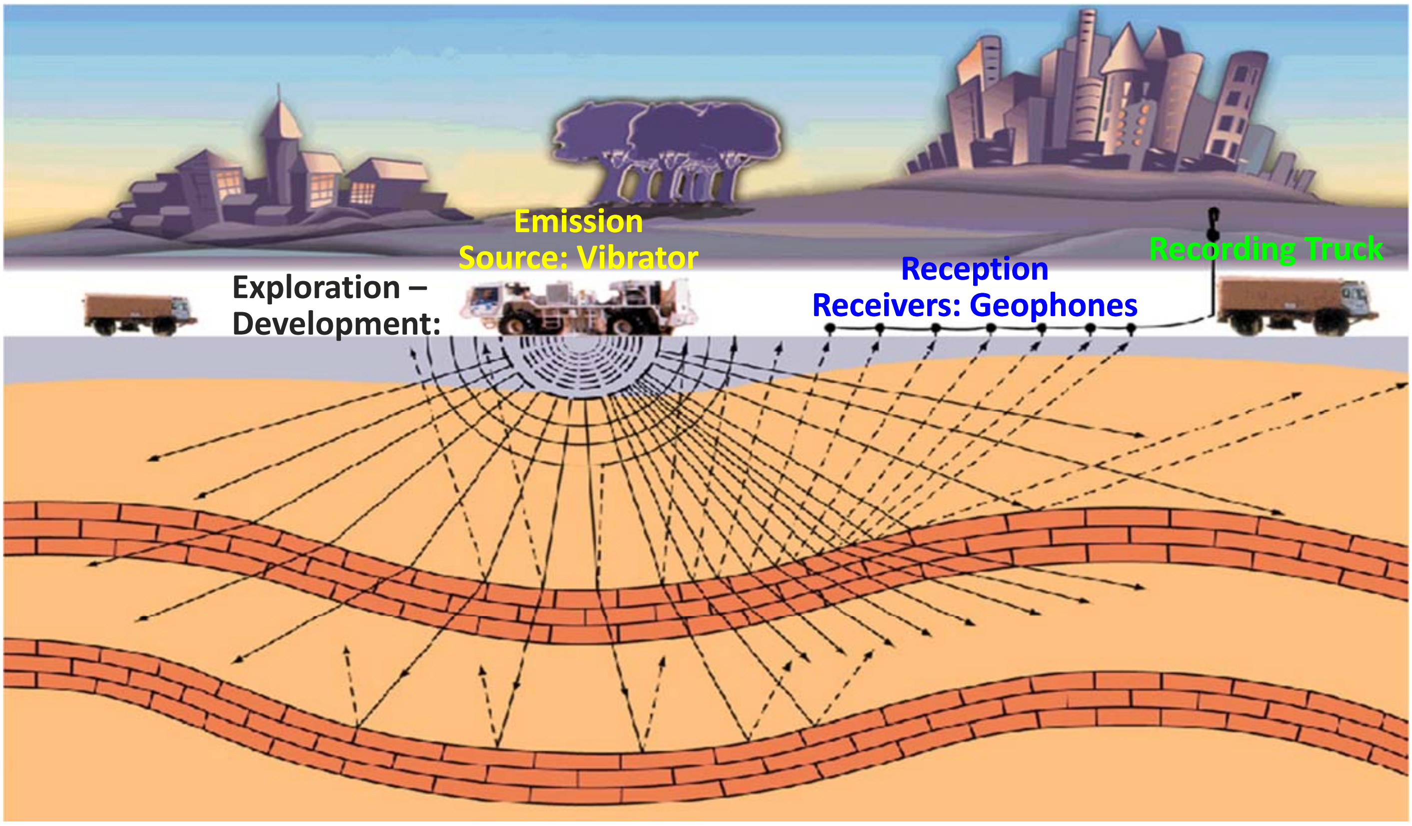
Actors in exploration & production activities



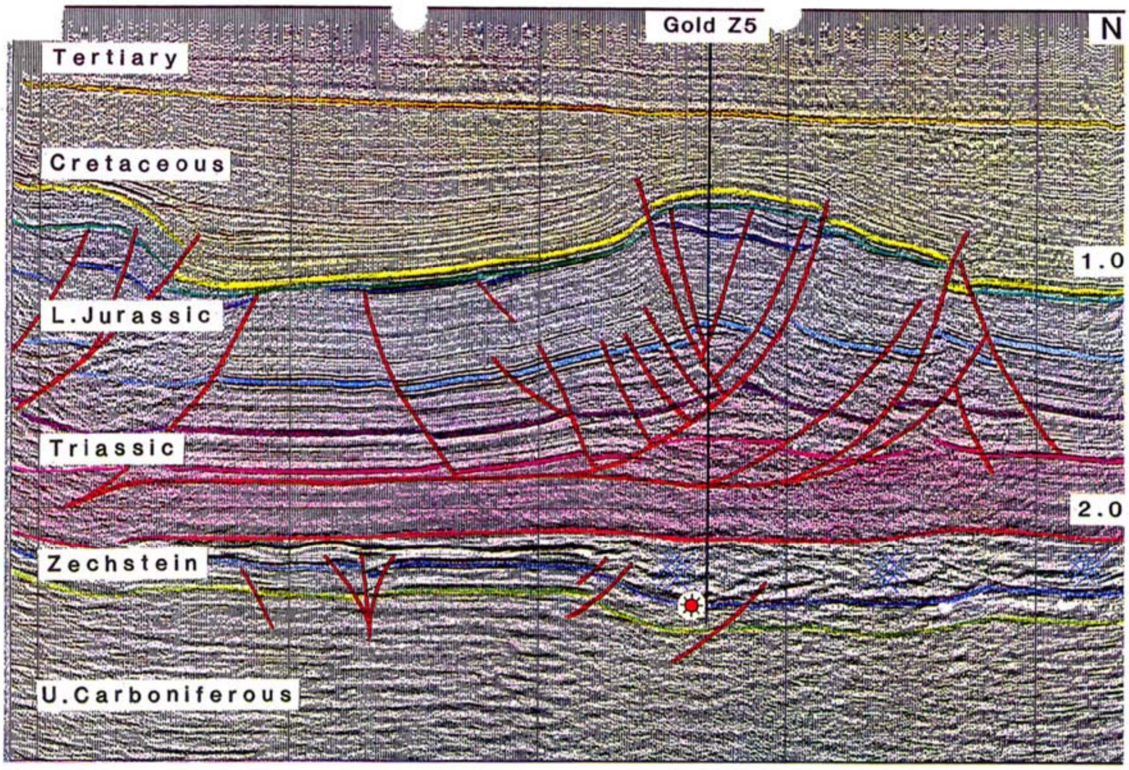
Seismic surveys

- **Purpose**
  - To detect potential hydrocarbon bearing reservoirs
- **Reflection Seismic is like an Earth Scanning**
  - After shaking the earth with a seismic source, measurements of the arrival times of events attributed to seismic waves that have been reflected from geological interfaces
  - Reflected waves come back to the earth surface to receivers and recording system
  - Reflection Seismic is a very powerful tool due to the Depth of Investigation (down to 10 000 – 15 000 meters) and the Resolution Power (20 to 2 meters)

2D land reflection seismic principle

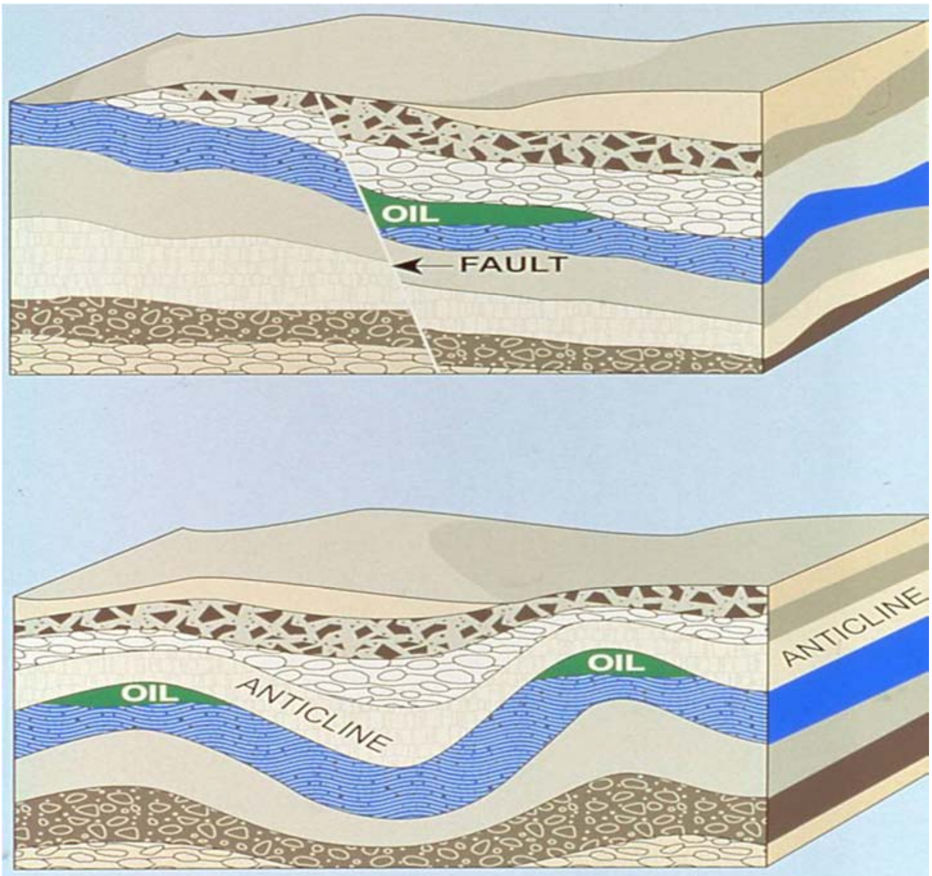


Seismic final objective: interpretation



North-south-trending seismic section showing inversion tectonics in the overburden. Reservoir carbonates, at 2.2 to 2.4 secs reflection time, are indicated in blue.

Some examples of traps



Drilling activities in E&P

Exploration		*Development*		*Field life*	
approx 2 to 4 years		*Approx 2 to 3 years*	*Approx 1 to 3 years*	*10 to 25 years?*	
Exploration	**Appraisal**	**Pre-project**	**Development**	**Production**	**Abandon**
Drilling(s) *Logs, tests*	*Drilling(s)* *Logs, tests*	*Pre-engineering studies*	*Drilling(s) & Completion*	*Well servicing* *Well Interventions* *Infield drilling(s)*	*Well(s) P&A* *Decommissioning*

First Oil

Drilling activities…:

Main steps of well operations (typical)

EXPLORATION/APPRAISAL

Rig moving in

↓

Well spudding
Drilling/casings to target

↓

Logging

↓

Testing *

↓

Plug & Abandon (P & A)

↓

Rig moving out

DEVELOPMENT

Rig move from previous well slot

↓

Well spudding
Drilling/casings to target

↓

Logging *

↓

Completion

↓

Rig move to next slot

↓

Connect flowline

: optional

Well objectives and drilling

- **Objectives of Exploration wells**
  - To drill in a safe and environmental-friendly manner
  - To identify all the geological layers and targets
  - To gather required and planned information

- **Objectives of Development wells**
  - To drill in a safe and environmental-friendly manner
  - To maximize the producer/injector capability
  - To optimize technical and cost performances (learning curve)

NB: cost of wells (DRILLEX) represents (approx), …

- *30 % approx. of CAPEX (onshore projects)*
- *25 % approx. (subsea, deepwater projects)*

General operating process for an Oil Company

- **For well construction several Service Companies (> tens) will be contracted and mobilized to:**
  - Provide a drilling unit (the rig)
  - Provide all the services associated with drilling activities: cementing, logging, testing…
  - Provide logistic means
- **The Operator is responsible for the Well Design, the Supervision and the “Quality” of the Operations**

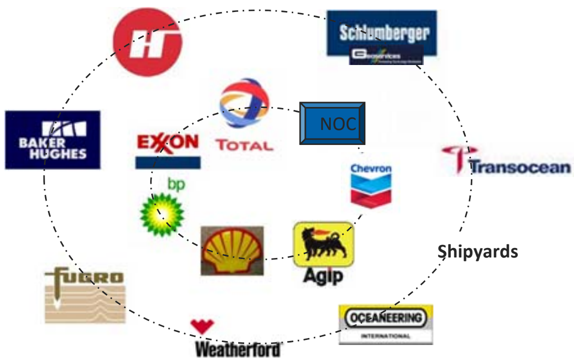
<u>NB</u>: Well costs: from 1 M$ up to … 80 M$

Drilling: Operator, Service Companies & Vendors

OIL COMPANY
or (the Operator)

The Operator is responsible for the Well Design the Supervision and the “Quality” of the Operations.

- **Service Companies or (the Contractors)**
  - **- Drilling contractor**
  - **- Logging services**
  - **- Cementing serv.**
  - **- Directional serv.**
  - **- Mud serv.**
  - **- Casing crew serv.**
  - **- Testing serv.**
  - **- Logistics serv. (helicopter, supply vessels…)**
  - **- ROV serv.**
  - **- Etc.**
- **Vendors**
  - **- Drilling bits, wellhead, casings, liner hanger,**
  - **- Etc.**



Service Companies, Vendors provide expertise and technical solutions

Drilling introduction

- Actors in exploration & production activities
- Roles of an oil company (the operator) and of service companies
- Main steps of well operations
- Well objectives and drilling

Drilling & Safety

IFP Training

Drilling – Safety

- Due to the very high level of risks involved, safety must be given the highest priority at all steps of drilling activities...
- During drilling operations, keep in mind that the safety of personnel must be placed above all the other considerations

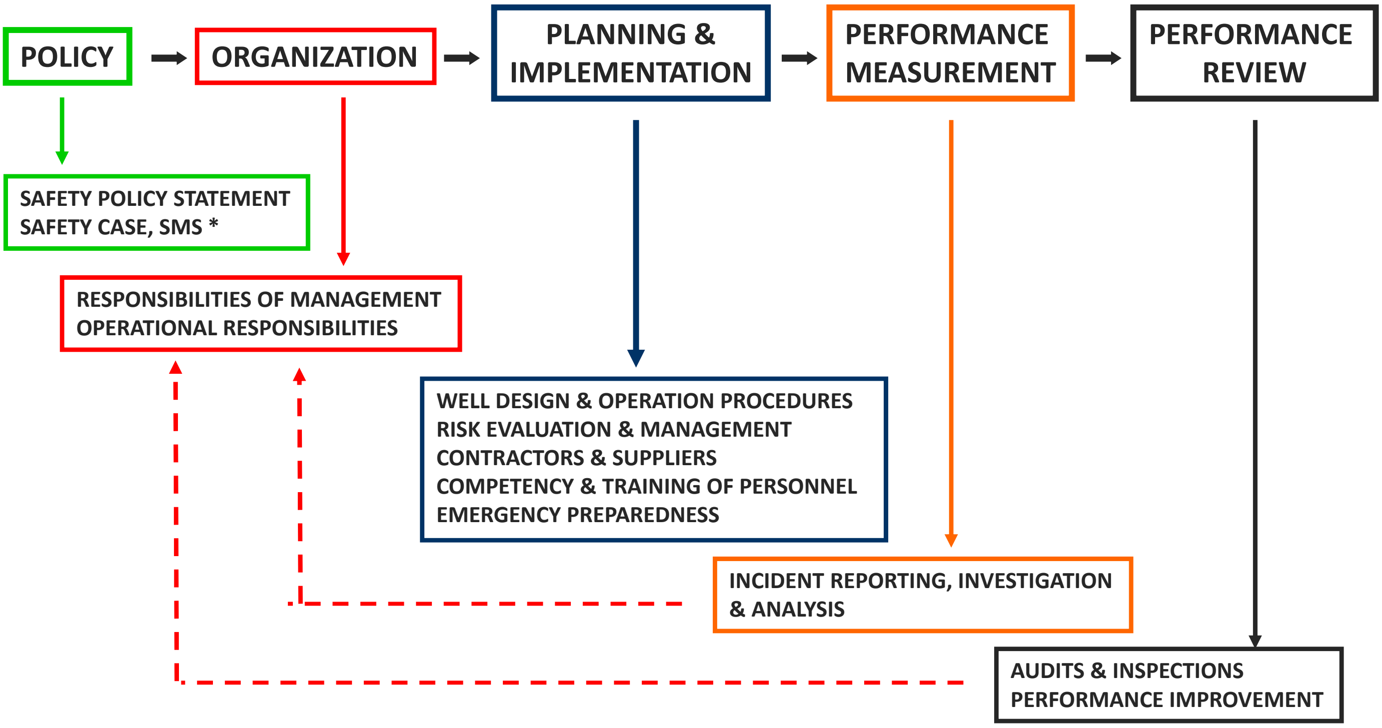
So, constantly, maintain

SAFE WORKING CONDITIONS

SAFE OPERATIONS

SAFE INSTALLATIONS

Drilling – Safety

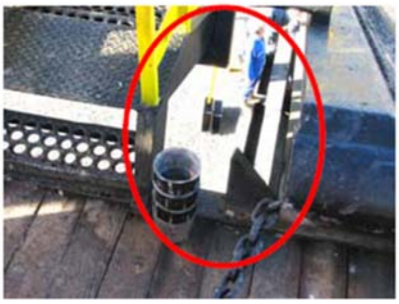


Hazards and associated risks

- **The following hazards and associated risks shall always be considered to the extent that they are applicable**
  - High pressure formation with risk of uncontrolled kicks (blowout)
  - Presence of gas on the drill floor with risks of explosion/fire
  - Presence of others vessels/other installation with risks of collision
  - Adverse weather conditions
  - Vessel stability
  - Work at height with risks of falling objects
  - Lifting activities with risks of falling objects and being struck/squeezed by the loads
  - Simultaneous activities (SIMOPS) during drilling and production on the same platform
  - ...

Example: risks of dropped objects

- **Drilling activities are always performed from different levels where employees work simultaneously**
- **Objects can fall:**
  - From the mast to the rig floor
  - From the rig floor to lower decks
  - Between different levels on complex installations



Risk prevention and mitigation measures

- **Technical**
  - Well barriers for drilling operations
  - Casing design
  - Pressure tests for well integrity
  - Well control equipment
  - Pressure tests & function tests of well control equipment
  - Well control & killing procedures
- **Transverse**
  - Hazards identification (job risk assessment, hazid)
  - Permit to work
  - Handling & lifting
  - Vehicles & driving
  - **Transportation of personnel**
  - Protective equipment
  - HSE training of personnel
  - HSE incident reporting and analysis
  - Emergency preparedness

Permit to work

This document is prepared before "the job" and must be signed by the HSE rep on the installation

1. **A control-barrier to prevent hazards**
2. **To ensure all foreseeable hazards are considered**
3. **To ensure communication to all necessary personnel**

Note 1: a "hot work permit" is required to perform any work that involves burning, welding, using fire- or spark-producing tools, or that produces a source of ignition

Note 2: a **job safety analysis** (JSA) is performed, when necessary, with the workers on the "job" location

" THE WORK PERMIT " → **RISKS REDUCTION**

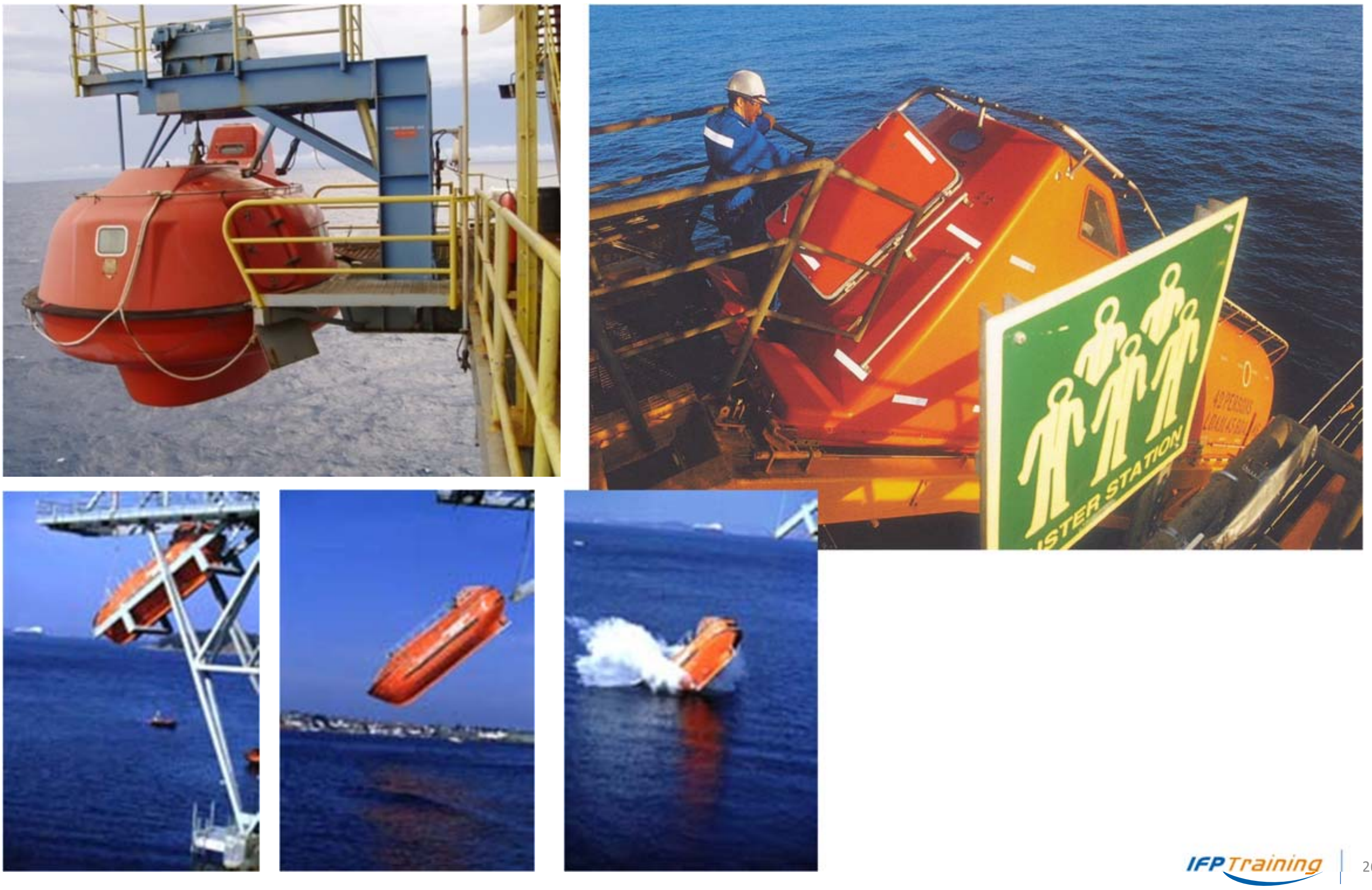
Drilling – Safety

Training

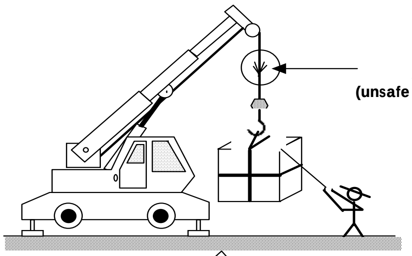
Develop / maintain a program for personnel safety training, including
For "*new comers*" and for senior employees!...

- **Offshore safety & survival training courses**
- **Well control courses**
- **Firefighting courses**
- **Defence driving courses**
- **Use of breathing apparatus**
- **Rig induction (*special instructions upon arrival at the rig site*)**
- **Fault tree analysis methodology**

Drilling – Safety



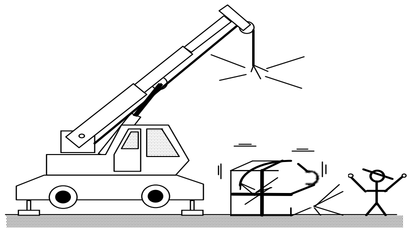
Incidents/accidents



ANOMALY
(unsafe act/condition)

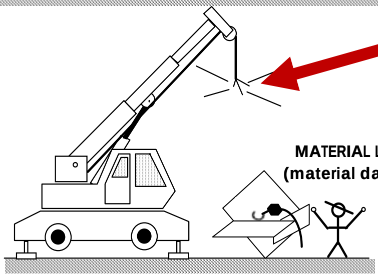
NEAR - MISS

NEAR-MISS
(no/minor damage)



CONSEQ.	HUMAN		ENVIRONM.		MAT/PROD	
SEVERITY	REAL	POT.	REAL	POT.	REAL	POT.
1	X		X	O	X	
2						O
3						
4		O				
5						

ACCIDENT



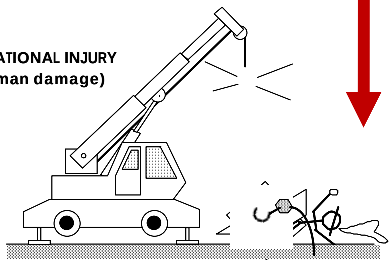
MATERIAL LOSS
(material damage)

CONSEQ.	HUMAN		ENVIRONM.		MAT/PROD	
SEVERITY	REAL	POT.	REAL	POT.	REAL	POT.
1	X		X	O	X	
2						O
3						
4		O				
5						

ACCIDENT

1 NEGLIGIBLE
2 MODERATE
3 SERIOUS
4 MAJOR
5 CATASTROPHIC

OCCUPATIONAL INJURY
(human damage)



CONSEQ.	HUMAN		ENVIRONM.		MAT/PROD	
SEVERITY	REAL	POT.	REAL	POT.	REAL	POT.
1			X	O		
2					X	O
3						
4	X	O				
5						

Reporting

- The near misses and incidents/accidents that may occur on a site will always have the same basic causes

These causes are the anomalies

- The most efficient means to dig up anomalies is to thoroughly analyze all incidents, and especially the near misses that should not be considered as faults or mistakes but as opportunities

Incident/accident analysis

- **As an accident is always the result of a combination of several causes (causal chain of events)… Nowadays accidents occurring during drilling activities, are often analyzed by the "fault tree analysis" method**
- **Through this methodology only preventive measures are looked into**
- **No blame approach during the investigation process**
- **Methodology – Principle:**
  1. List and draw up all facts
  2. Build the "tree"
  3. Look for all possible causation chain
  4. Select one (or more) causation chain to explain the incident

Without identifying the root causes (contributing factors), preventing similar incidents in the future is hopeless

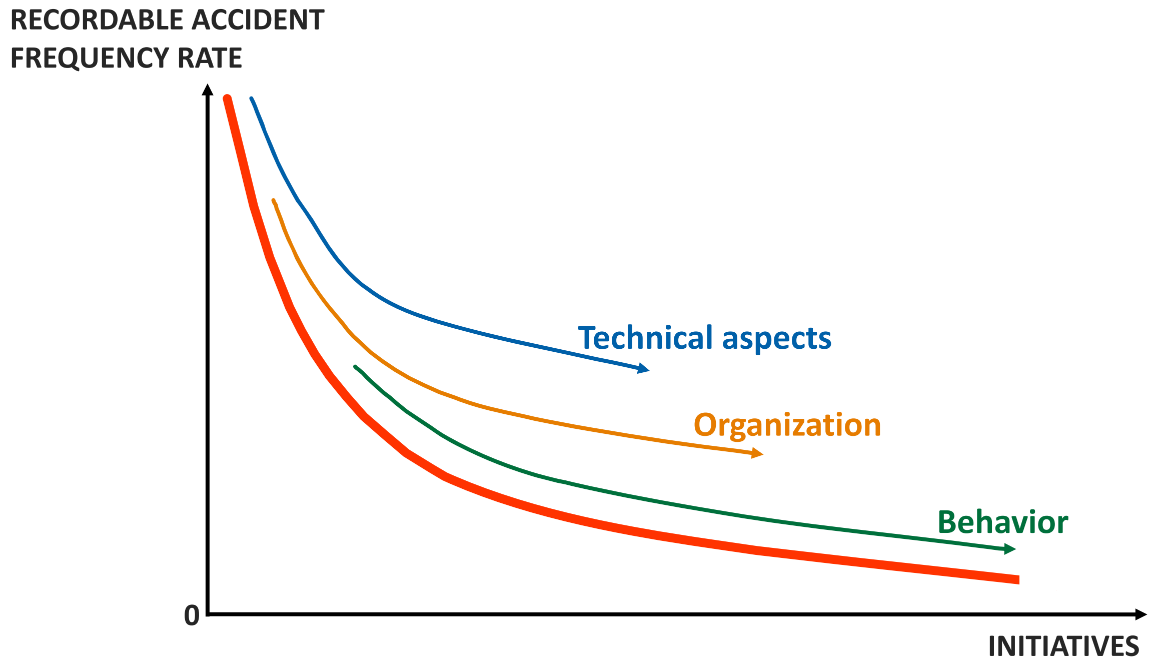
Emergency control

- **A particular consideration will be given to "emergency responses" as operations are often conducted in an isolated and / or adverse environment**
- **Emergency response plan (ERP):**
  - Covers any emergency incident including injuries, spills, well control, fires, and other events causing harm to people, damage to the environment and/or loss of property (organization, communication)
- **The BOCP (Blow Out Contingency Plan) provides an effective response in the event of a blow out, in order to:**
  - React promptly
  - Minimize the consequences on people, the environment and company assets
  - Restore control as soon as possible

EMERGENCY DRILLS…

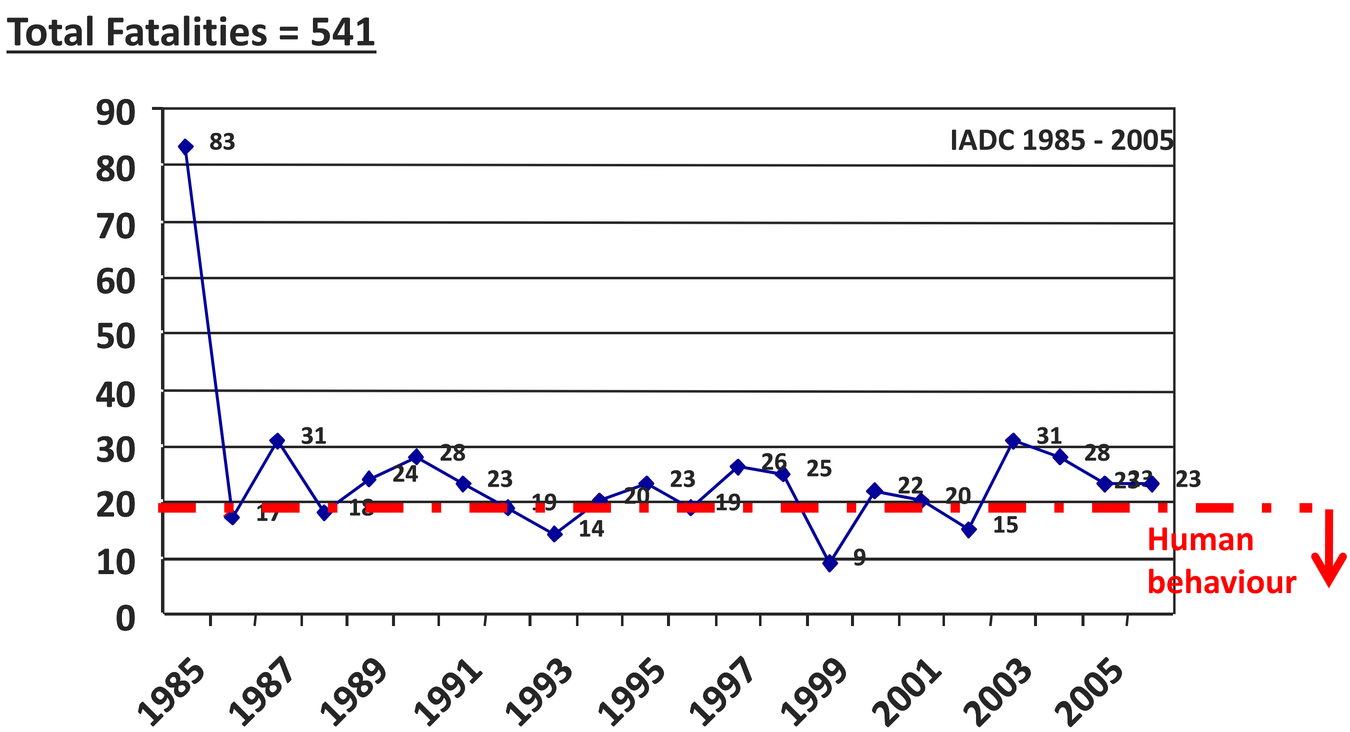
Human factors

- Where to act… Which initiatives…



Death records

- A lot done, but still a lot to do…



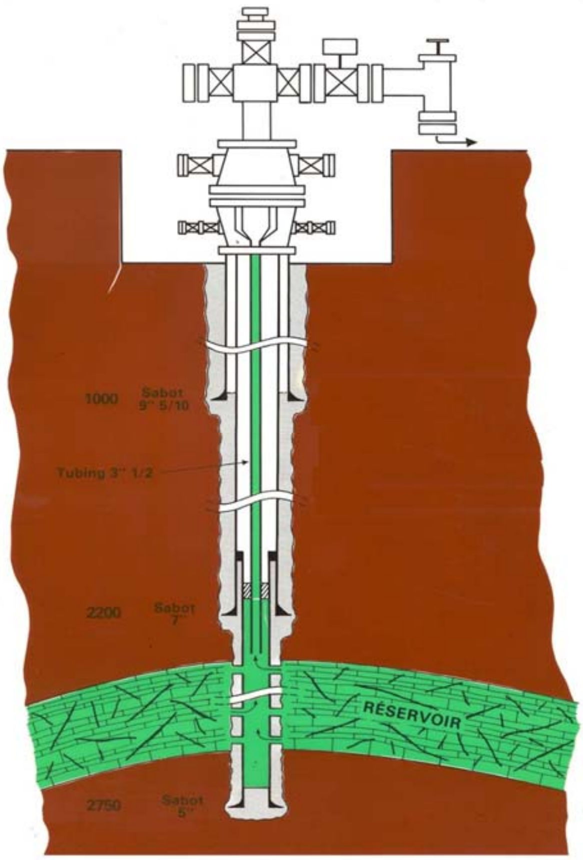
Key points to keep in mind

- Near-misses and accidents are always the result of a combination of several causes
- The reporting together with the analysis of the anomalies and the near-misses are of major importance for efficient safety at work
- Without identifying the root causes (contributing factors), preventing similar incidents in the future is hopeless
- Many behavioral competences are necessary to work on a drilling site but none is more important that being a good communicator (relationship with other)

Well Engineering

Well purposes

- Provides **access** to underground reservoir
- Ensures **efficient communication** between reservoir and wellbore
- Provides a **vertical conduit** to convey hydrocarbons **efficiently** and **safely** to the surface
- Includes at the surface, pressure-containing equipment to **control** production and allow downhole **intervention** for maintenance, repair, …



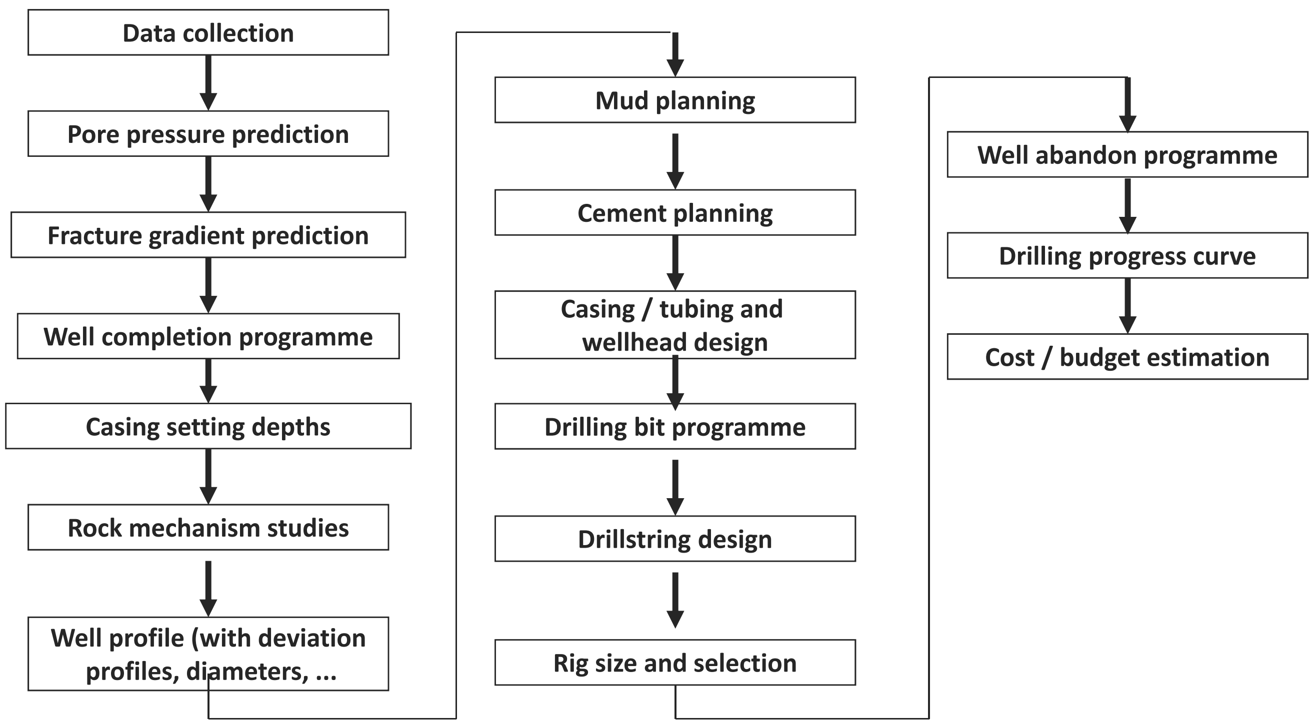
Well design

- **Based on the Well Prognosis issued by the Geosciences Department, and including**
  - The anticipated overburden layers (nature & lithology)
  - The anticipated depths of various overburden layers and of reservoir(s)
  - The anticipated temperature & pressure gradients (pore, frac)
  - Information on potential anomalies (high pressures, …)

- **… the Drilling Department will design the well architecture, will prepare the Drilling Program, including**
  - The well profile
  - The casing setting depths
  - The rig and all equipment for well construction
  - The duration of the various operations: well progress curve
  - The well budget

Well design

Overview of well engineering studies

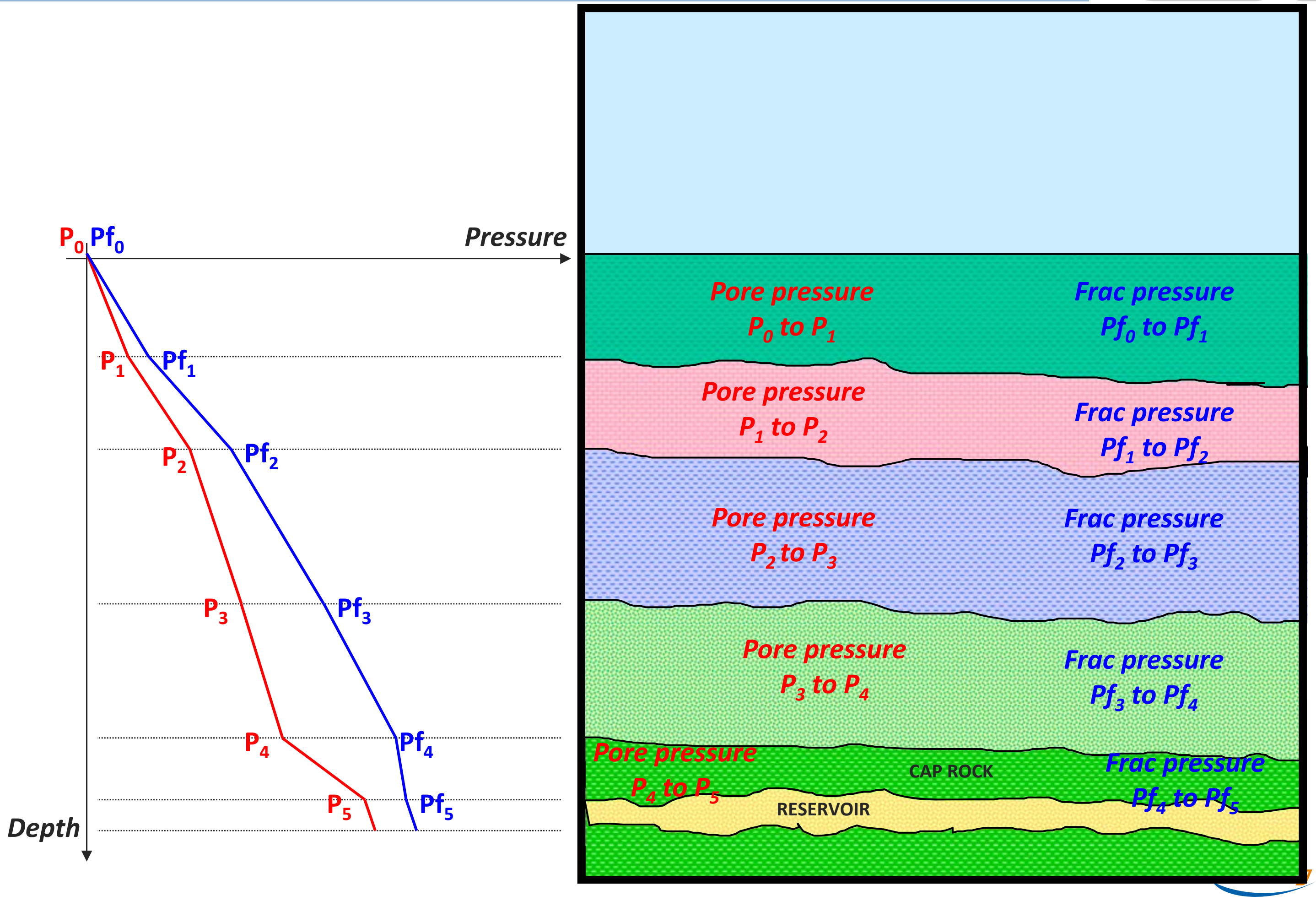


Well design

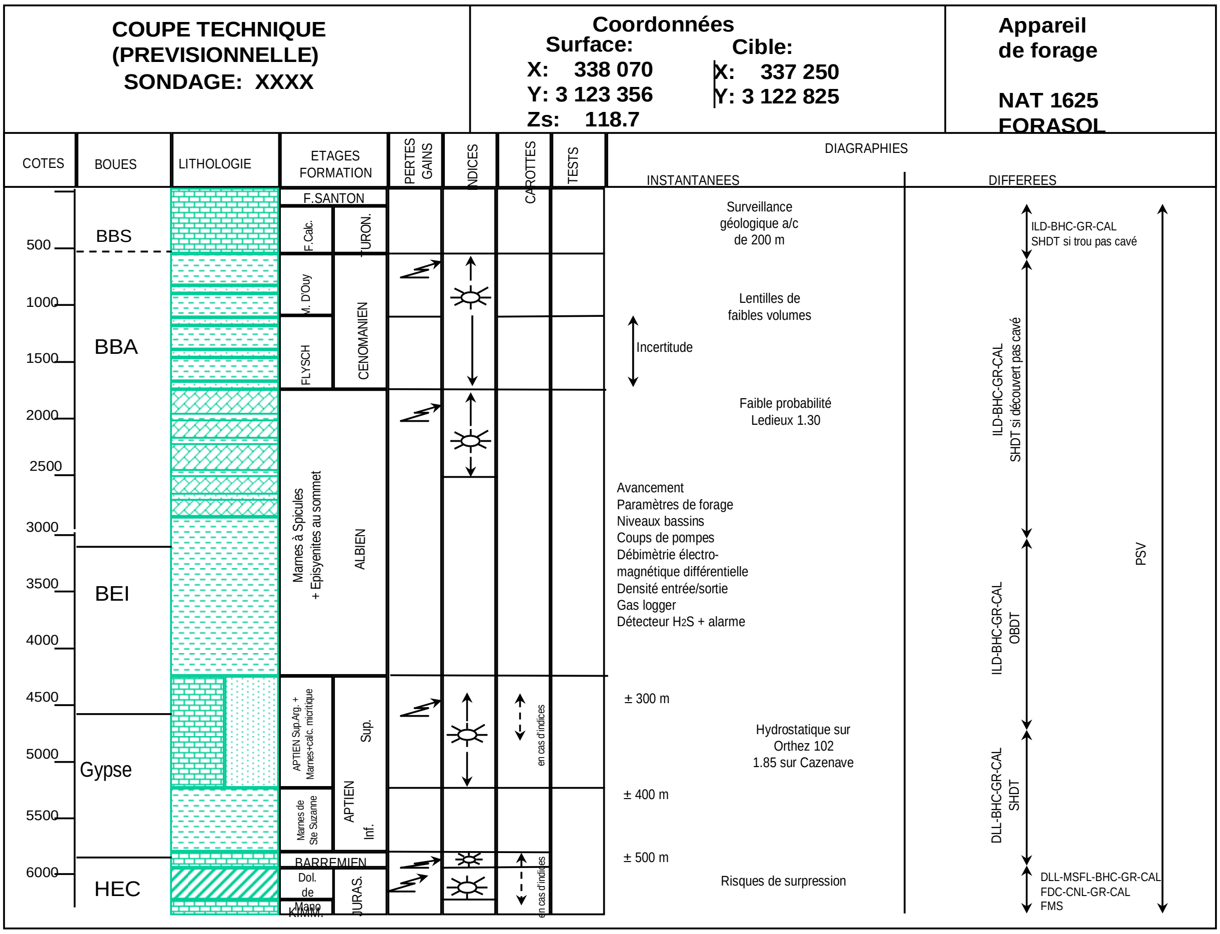
Geological Program Contents

- Geographical location: site, environment, surface location, specific constraints, reference wells, ...
- Objectives: main, secondary objectives, tolerances on target(s)
- Lithological column: description of the sequence of formations, levels, age, characteristics, true vertical depth of each level
- Expected pore pressure profile / expected fracturation formation pressure (LOT/RFT/DST...)
- Expected temperature profile
- Geological survey program
- Coring and logging program
- Characteristics of expected fluids (gas, oil, H2S or CO2, ...)
- Anticipated hazards

Well design pore and frac pressure profiles in the well



Lithology and anticipated program



Formation control pressure

Hydrostatic pressure laws

Hydrostatic pressure: pressure exerted by a column of fluid in a well at a given depth

$$P_h = \rho \cdot g \cdot H$$

P_h : Hydrostatic pressure at depth H (Pascal)
ρ : Fluid density (kg / m3)
g : Gravity acceleration (= 9.81 m / s2)
H : Vertical depth (m)

$$P_h = \frac{H \cdot d}{10}$$

P_h : Hydrostatic pressure at depth H (kg/cm2)
H : Vertical depth (m)
d : Fluid density (kg/l)

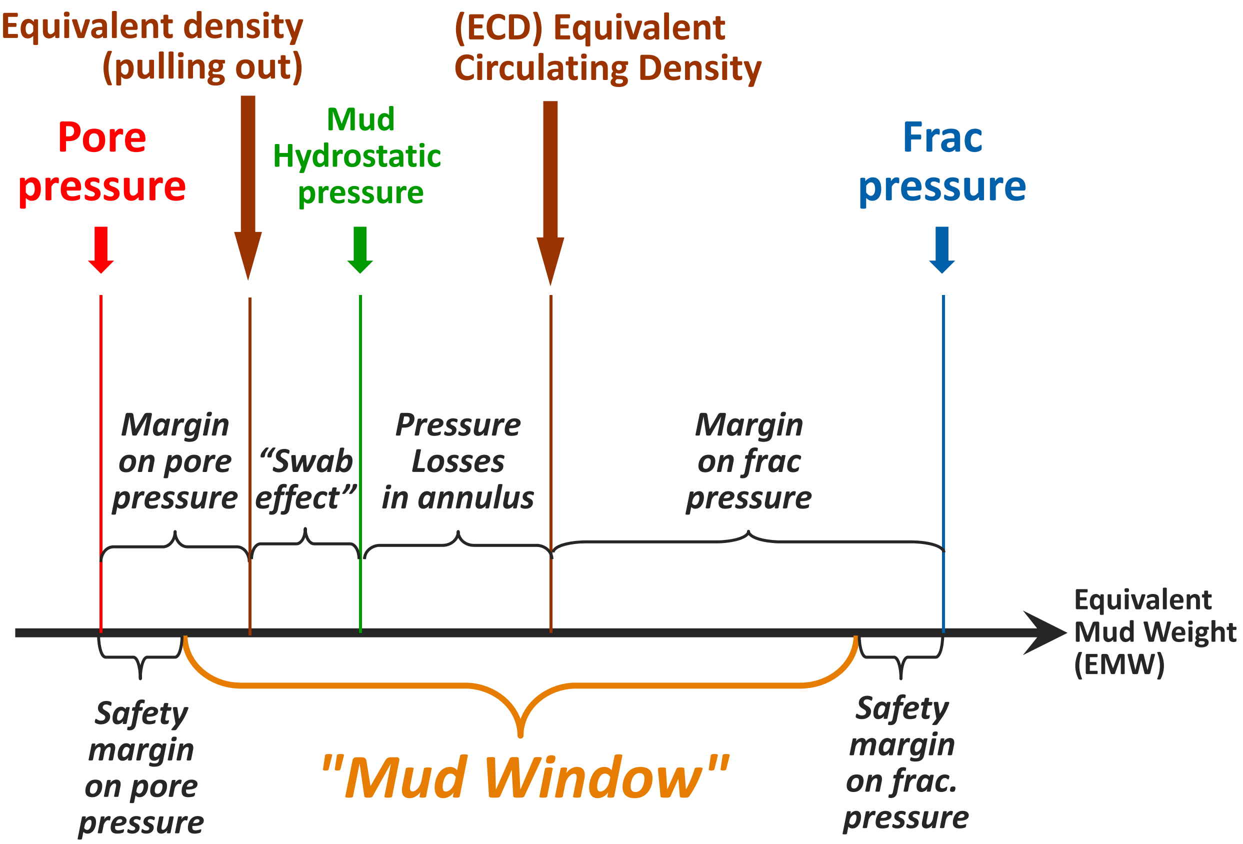
$$P_h = 0.052 \cdot d \cdot H$$

P_h : Hydrostatic pressure at depth H (psi)
d : Fluid density (lb/US gal)
H : Vertical depth (ft)

$$P_h = \frac{H \cdot d}{10.2}$$

P_h : Hydrostatic pressure at depth H (bar)
H : Vertical depth (m)
d : Fluid density (kg/l)

MUD WINDOW



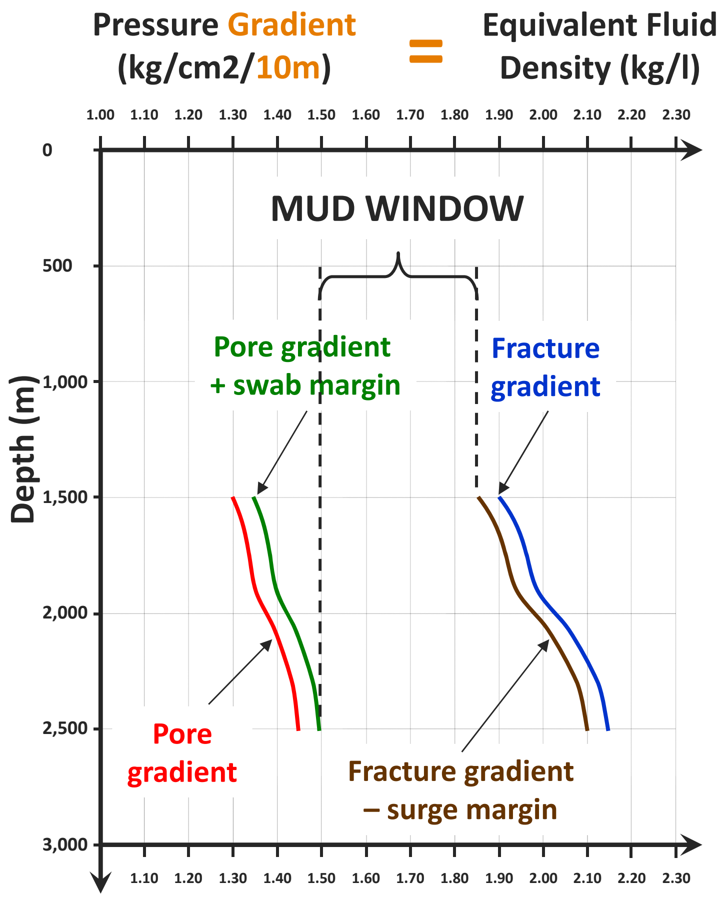
Hydrostatic Pressure

- What is the mud window to drill a hole section from 1 500 to 2 500m TVD?
  - Swab margin = 0.05 esg
  - Surge margin = 0.05 esg
  - Fracture gradient = between 1.90 and 2.15 esg
  - Pore gradient = between 1.30 and 1.45 esg

Mud Window =	....	sg

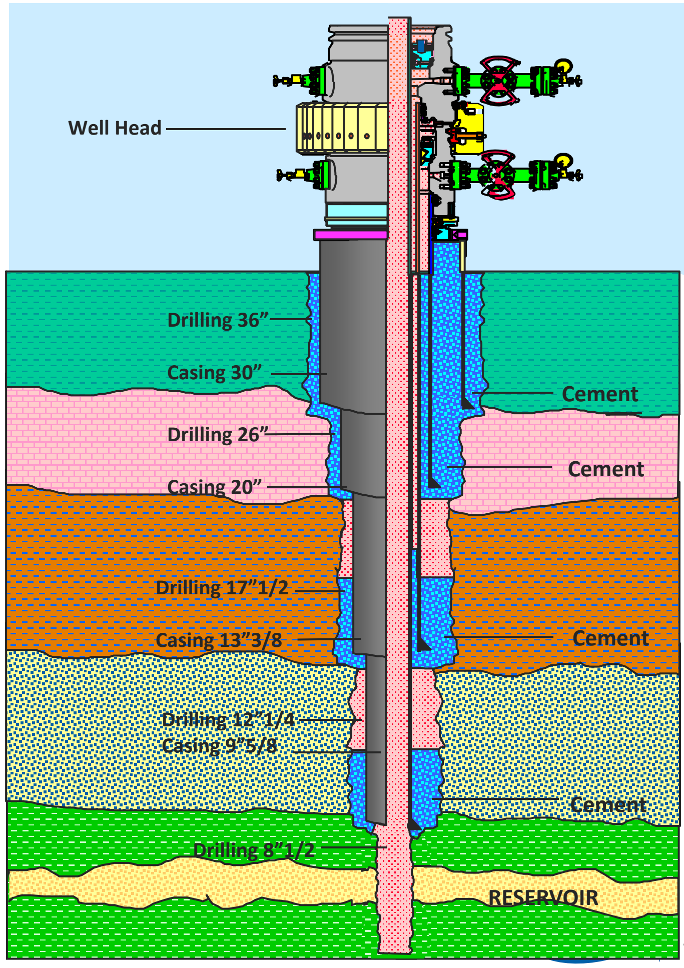
- What will happen if the mud weight used to drill the section is 2.0?

....



Casing design

- **Why several casings? What are the main roles of the casing strings?**
  - To protect unconsolidated or mechanically unstable formations
  - To “separate” formations with incompatible pore and frac pressure gradients
  - To protect different trajectory sections in deviated wells
  - To isolate reservoir layers, it allows selective production and receives the completion string inside
- **Different types of casing strings:**
  - Conductor pipe
  - Surface casing
  - Intermediate (or protective) casing(s)
  - Production casing (or liner)

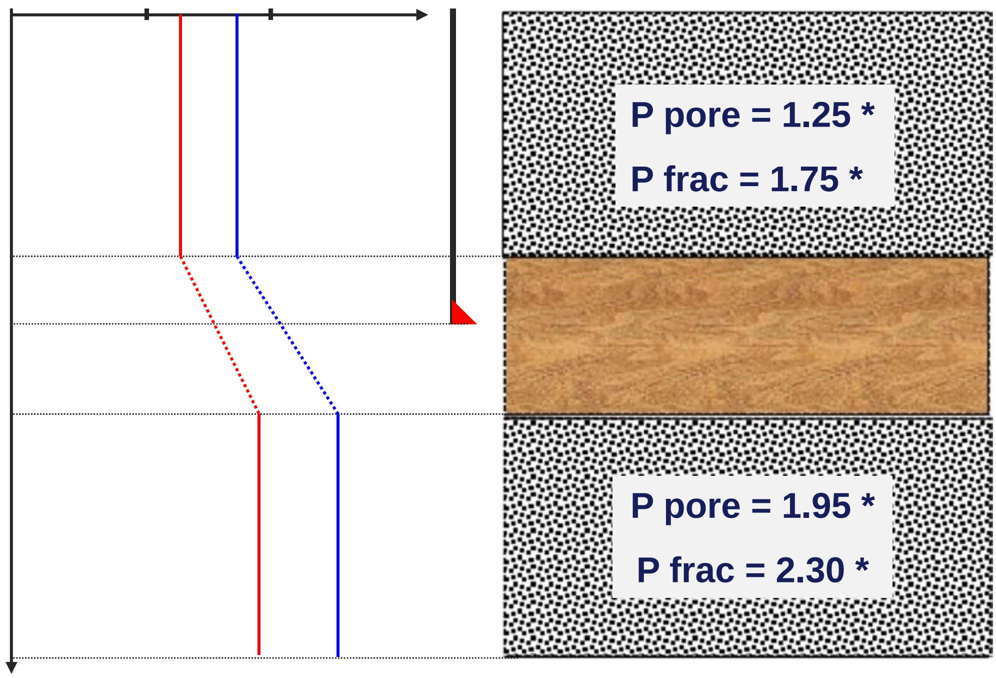


Casing design

Setting casing to separate incompatible formations

- Example -

Pressure gradient (kg/cm2/10m)
= Equivalent Mud Weight (kg/l)



Depth

Formation A

Porous & permeable
(Sandstones)

Formation B

Non-porous, non-permeable
(Shale)

Formation C

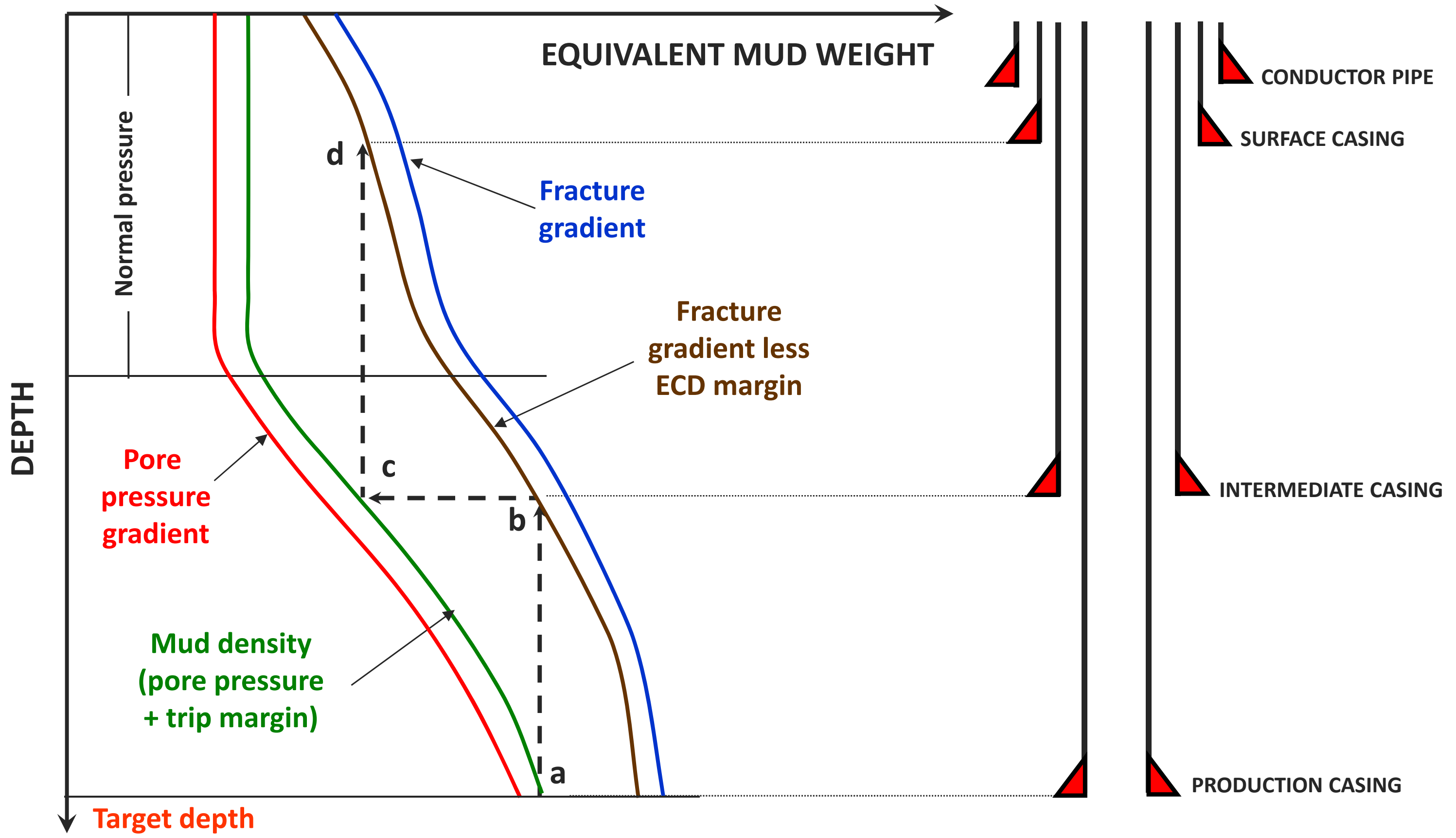
Porous & permeable
(Sandstones)

*: Pressure gradient or Equivalent Mud Weight

Need to set casing in Formation B before drilling through Formation C

Casing design

Selecting the Casing Setting Depths

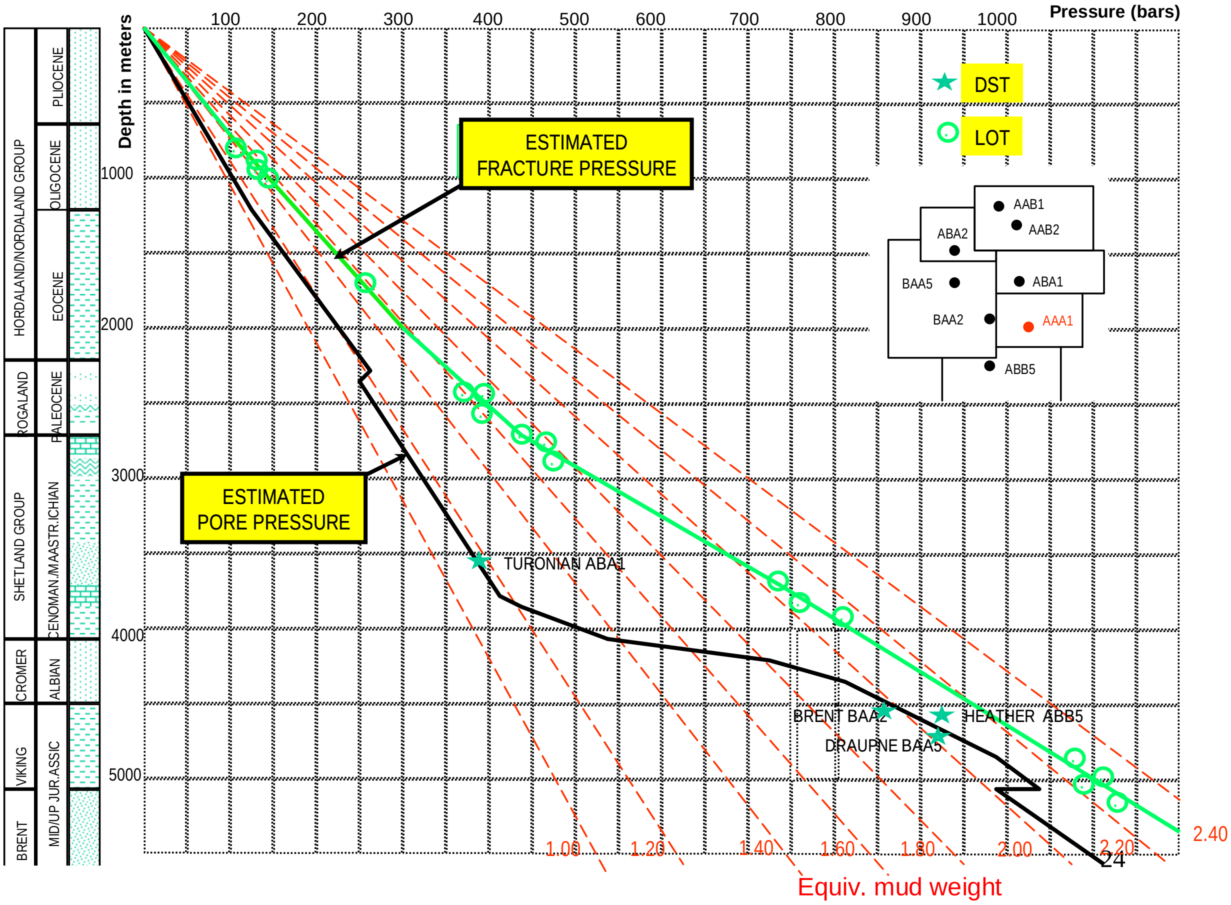


Casing design

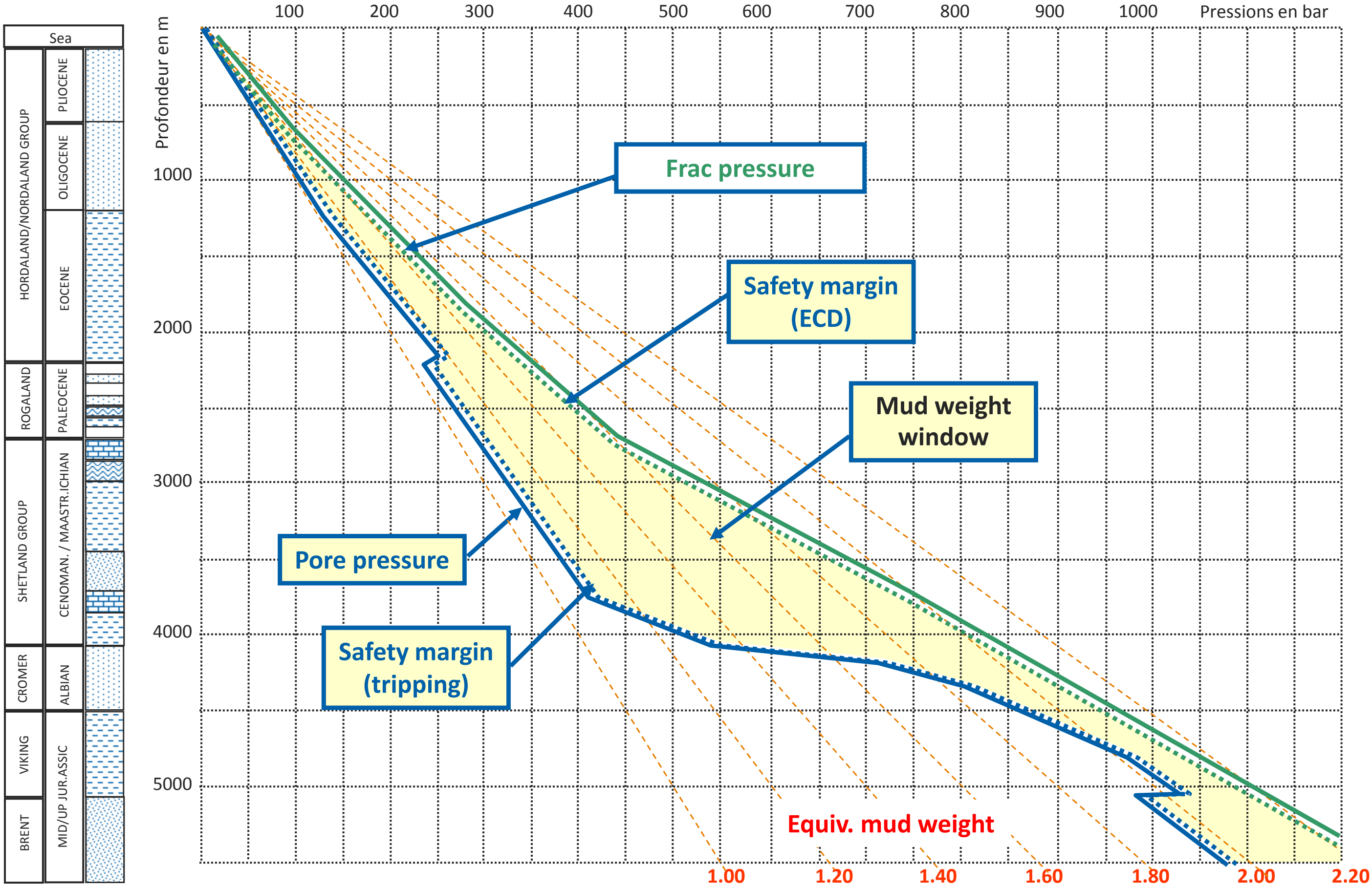
The well design depends mainly on

- **The final depth to be reached**
- **The pore and fracture pressure profiles of the formations**
- **The type of geological formations (composition, mechanical stability, …)**
- **The hole diameter required at TD, based on:**
  - The open hole logging and well testing requirements for **exploration well**
  - The completion design and tubing diameter for **development well**
- **Well trajectory (deviation angle)**
- **Potential drilling hazards**
- **Environmental and regulatory constraints**

Example of well design (1 of 10)



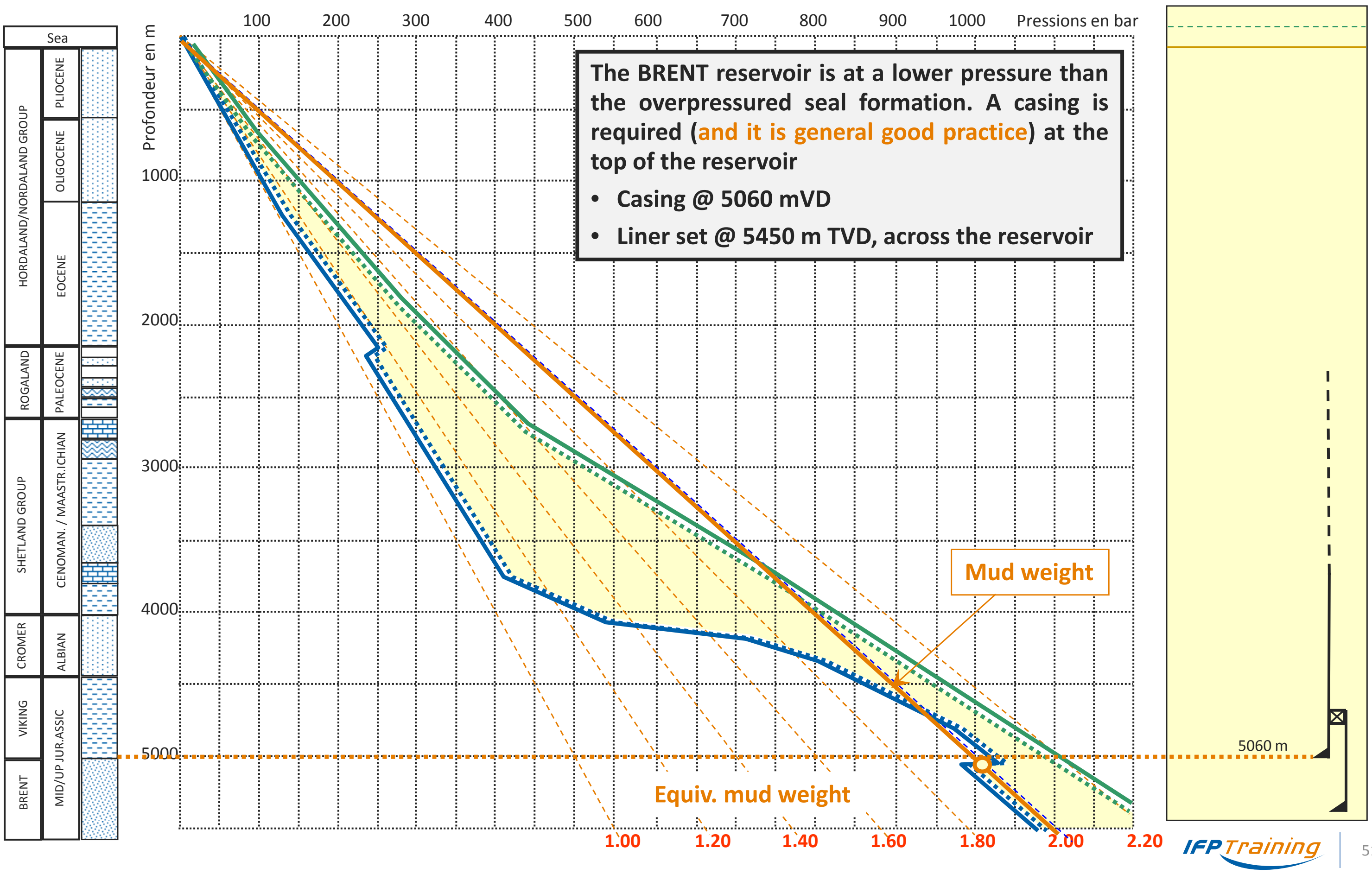
Example of well design (2 of 10)



Example of well design (3 of 10)

The BRENT reservoir is at a lower pressure than the overpressured seal formation. A casing is required (and it is general good practice) at the top of the reservoir

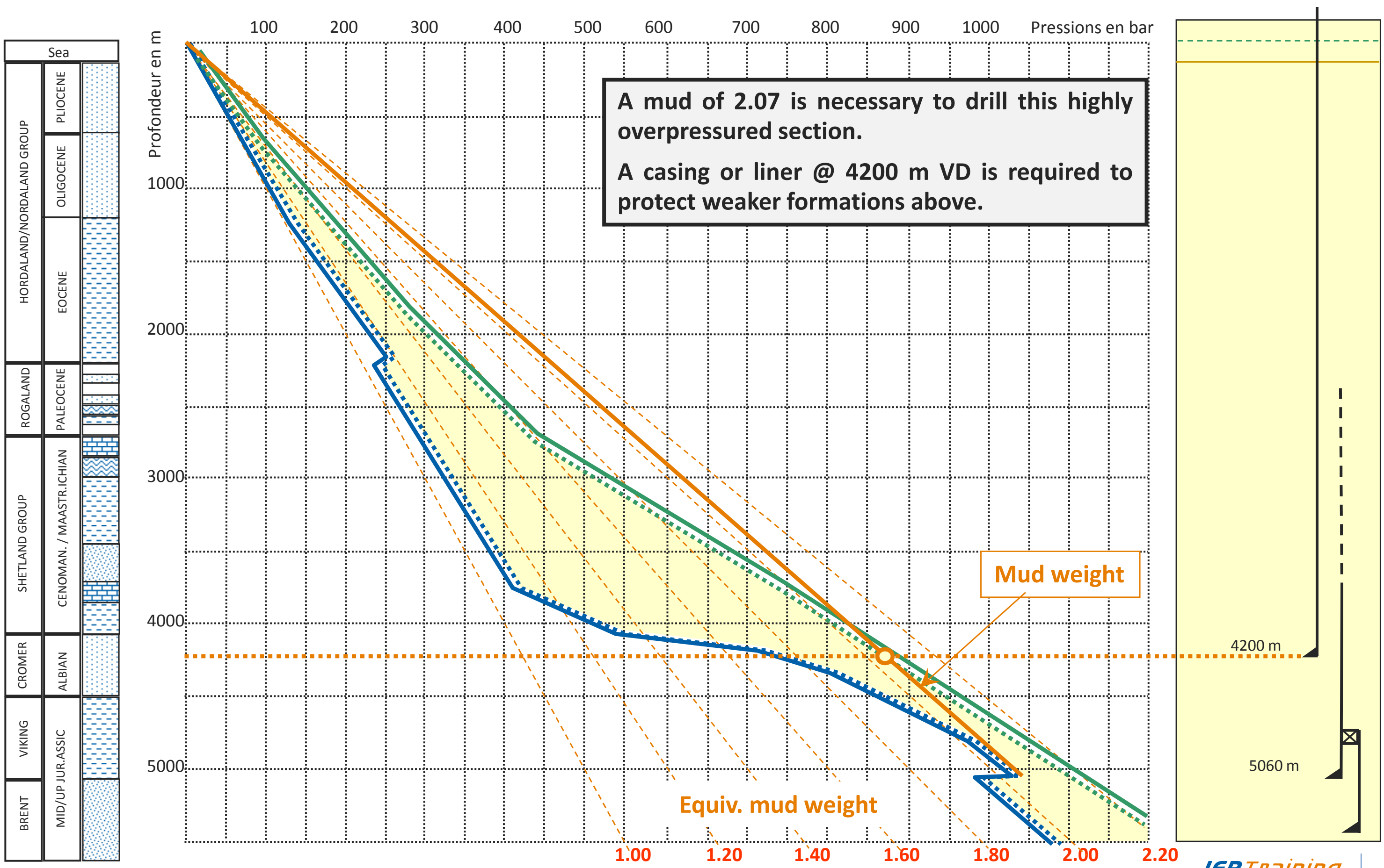
- Casing @ 5060 mVD
- Liner set @ 5450 m TVD, across the reservoir



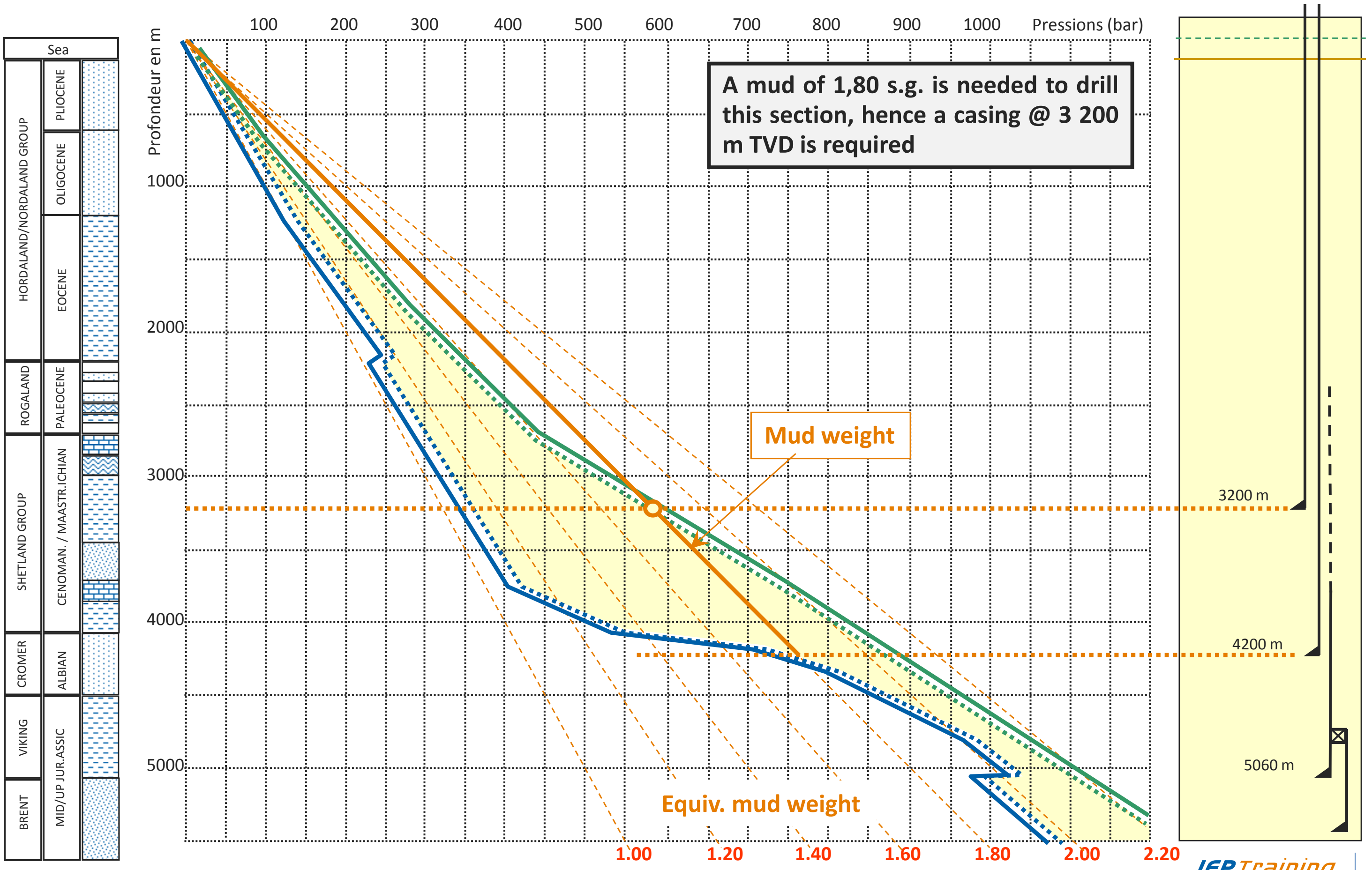
Example of well design (4 of 10)

A mud of 2.07 is necessary to drill this highly overpressured section.

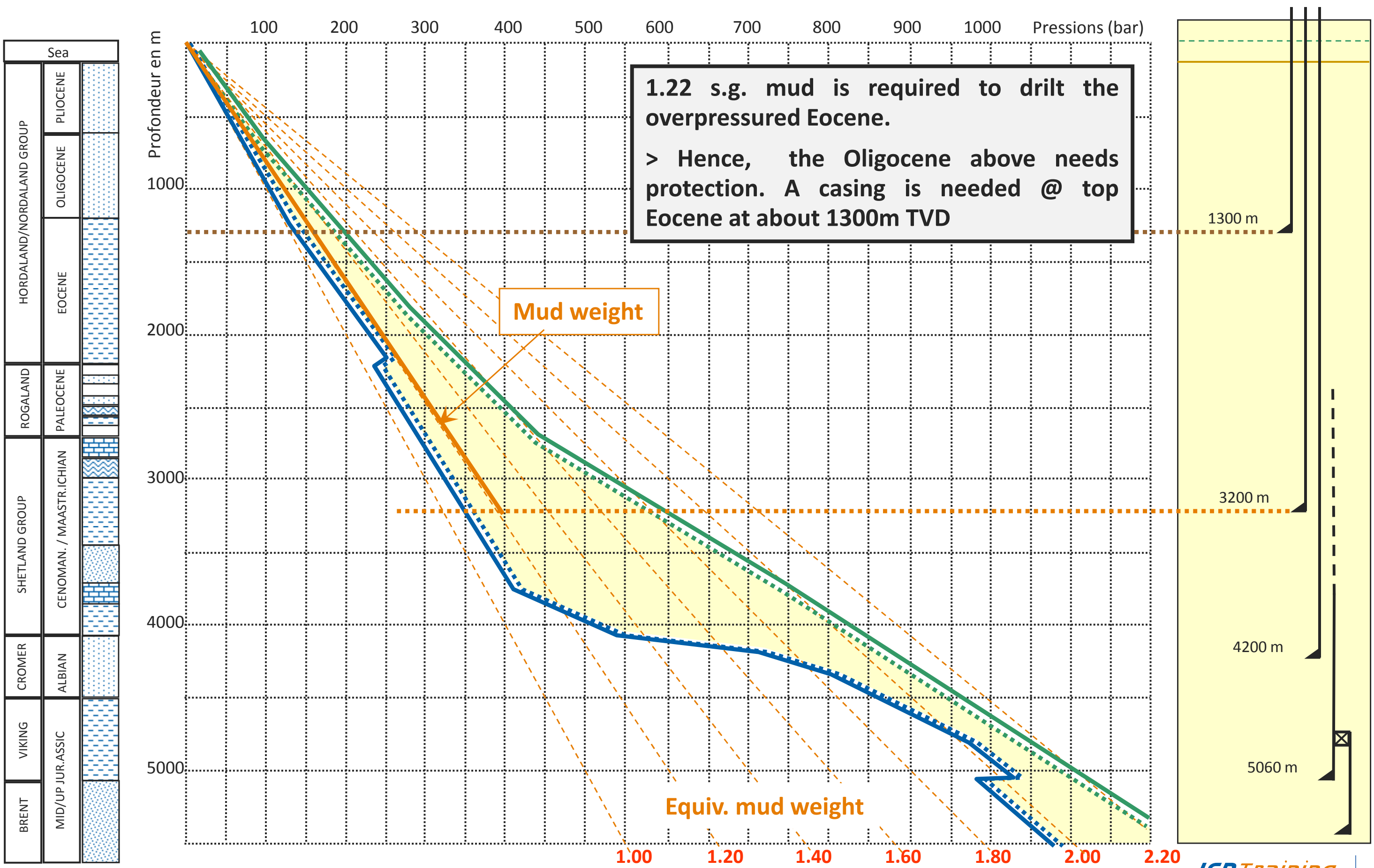
A casing or liner @ 4200 m VD is required to protect weaker formations above.



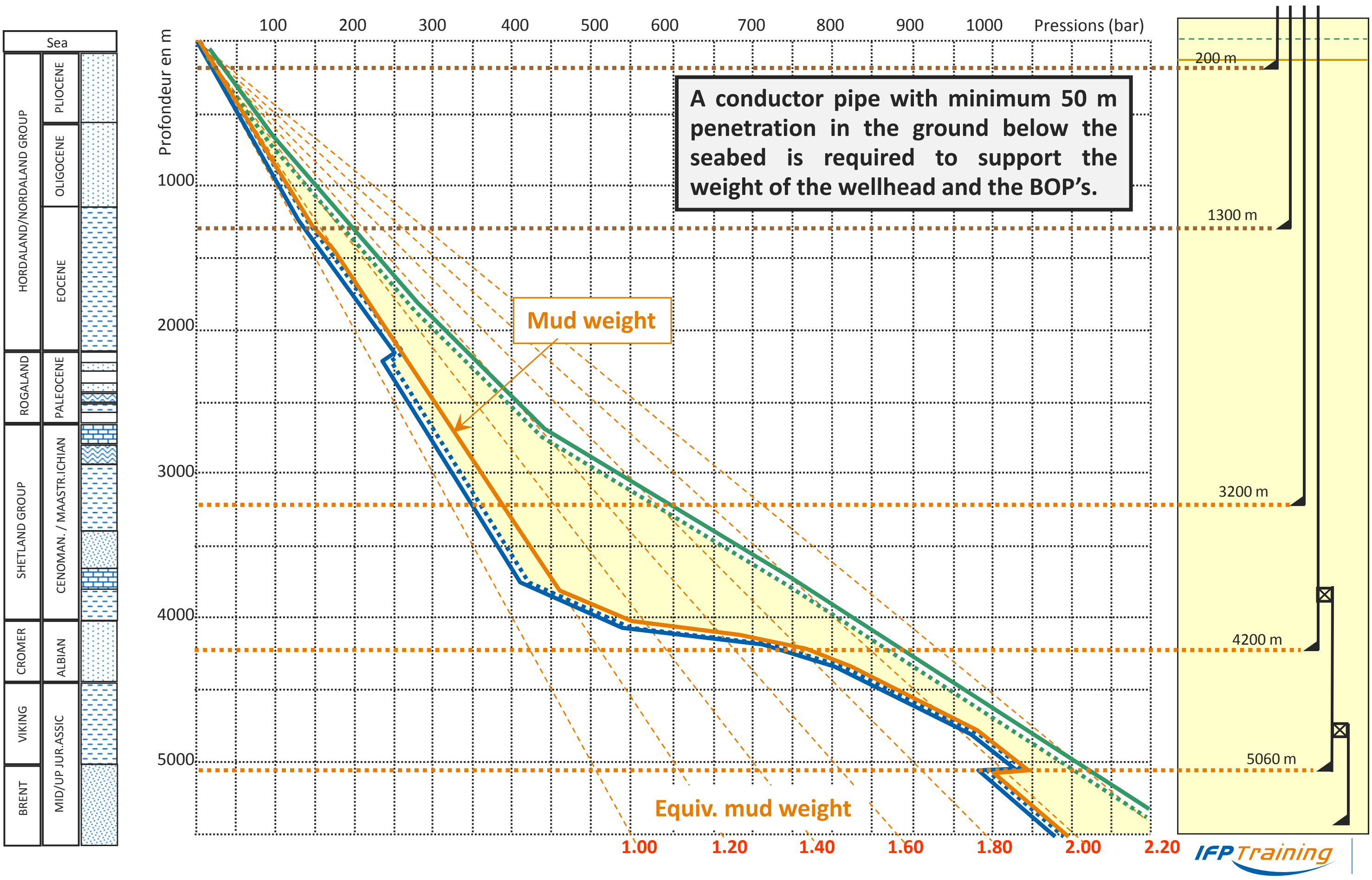
Example of well design (5 of 10)



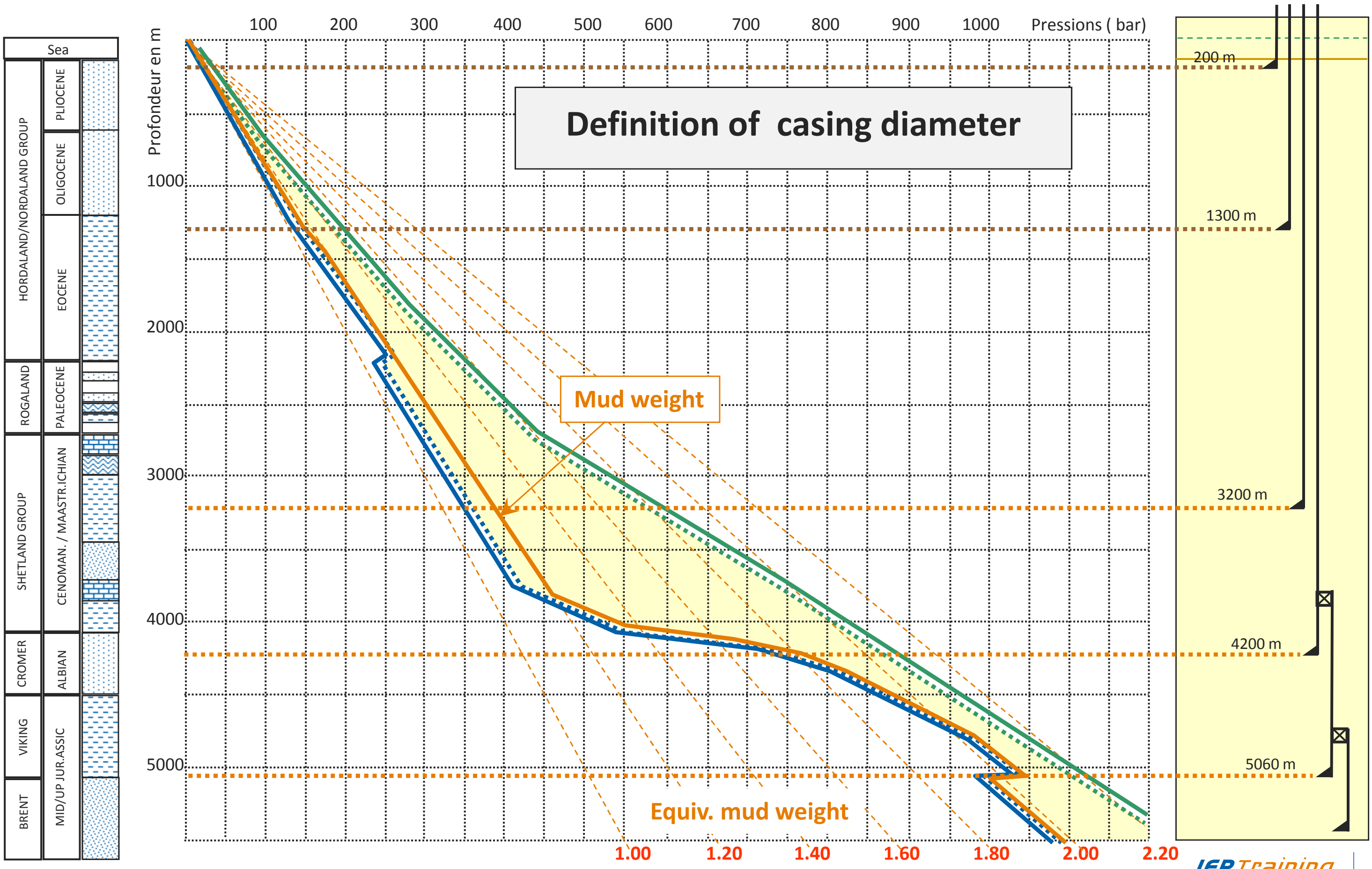
Example of well design (6 of 10)



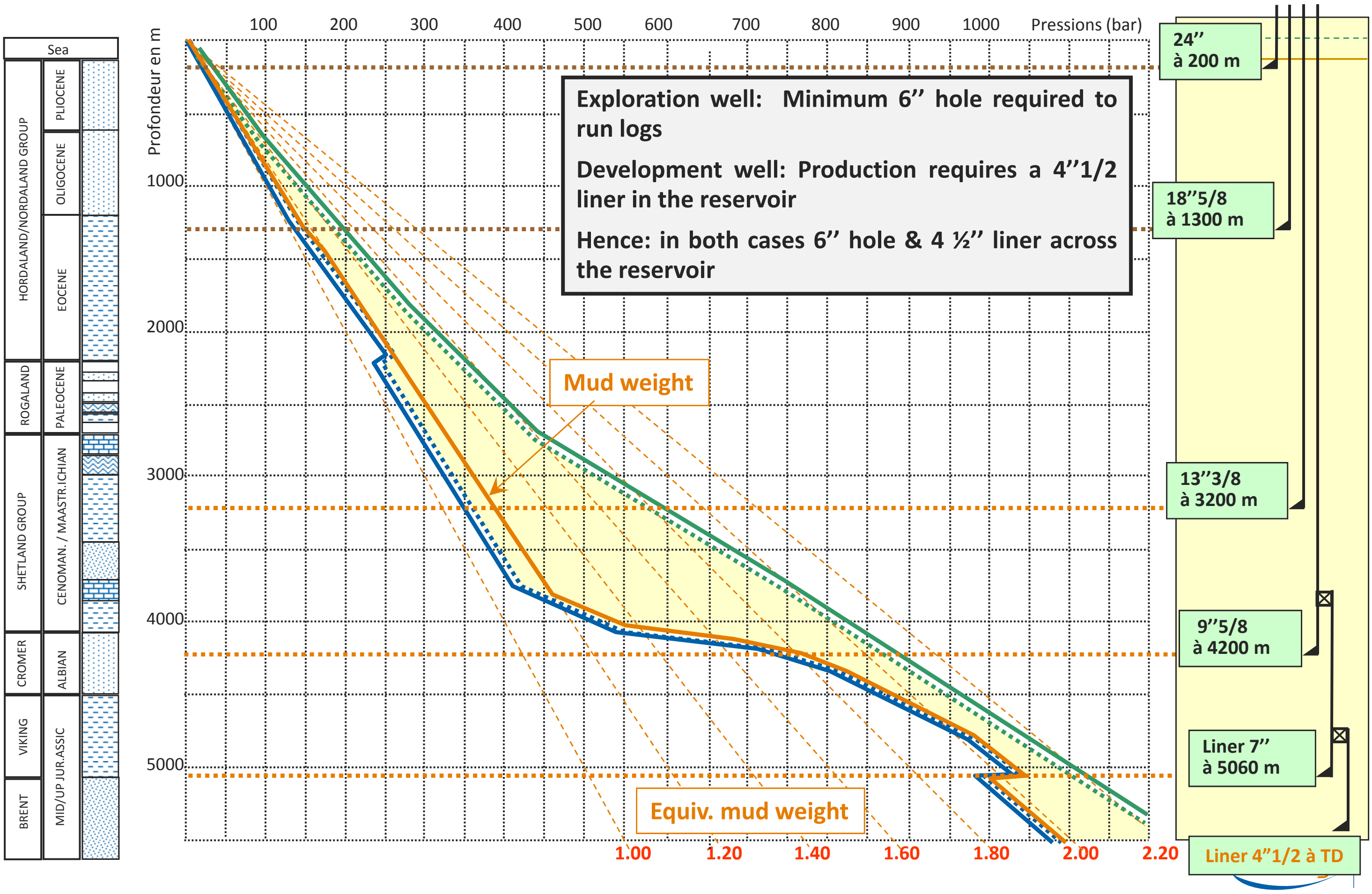
Example of well design (7 of 10)



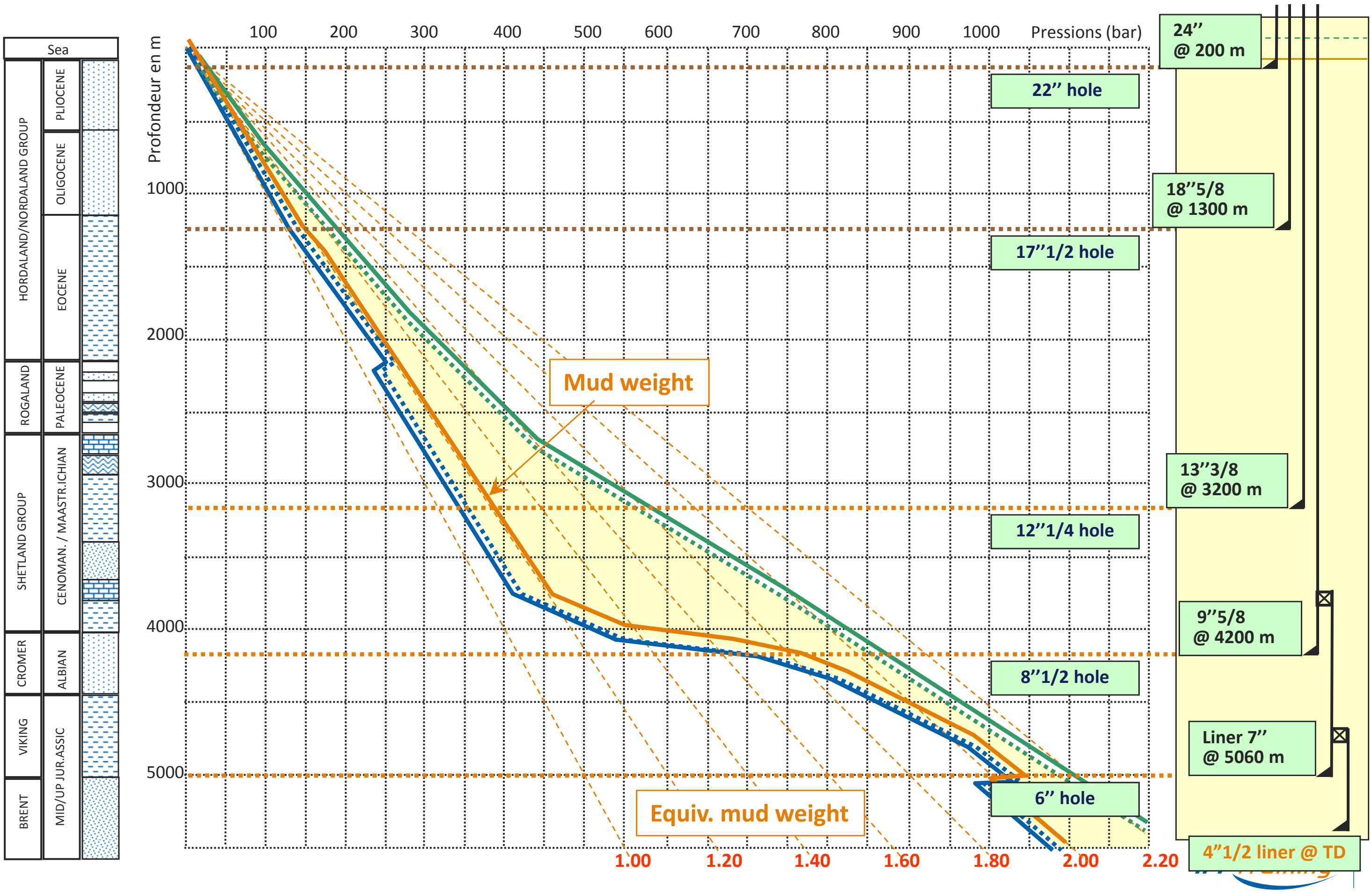
Example of well design (8 of 10)



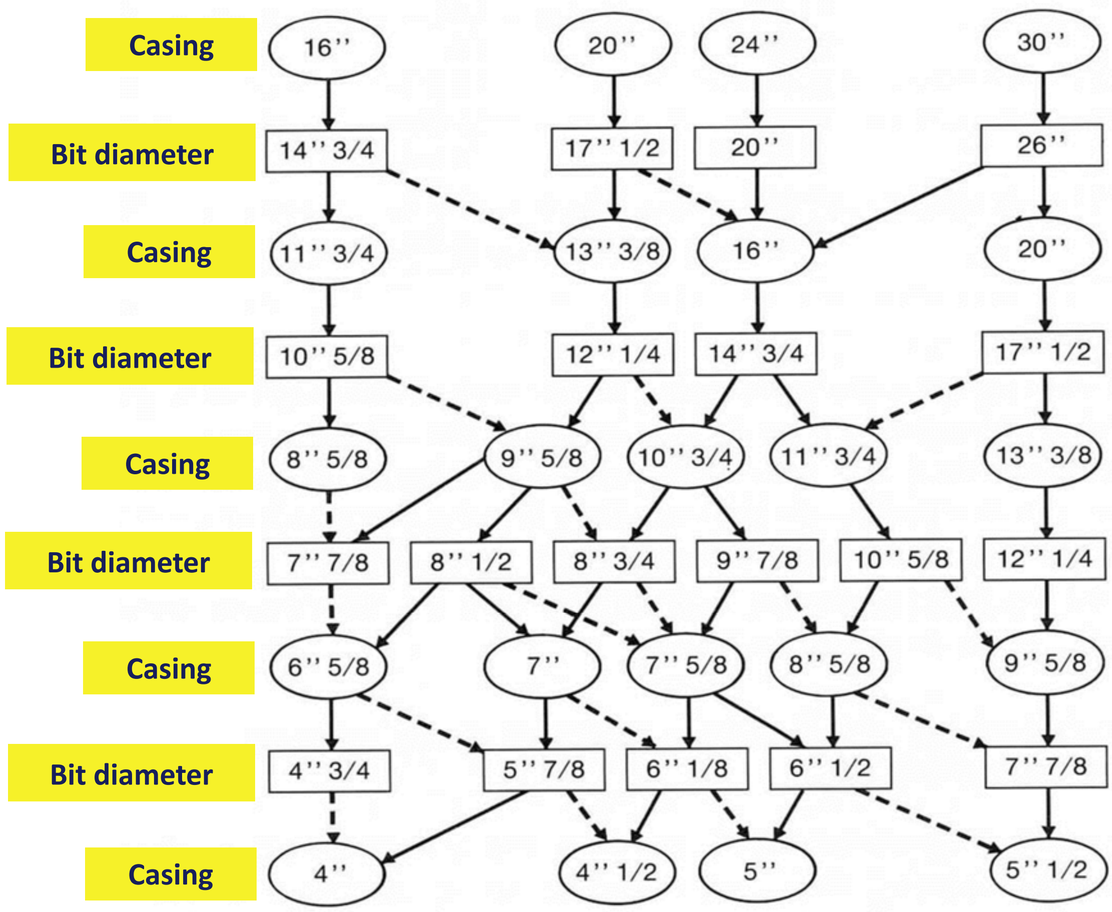
Example of well design (9 of 10)

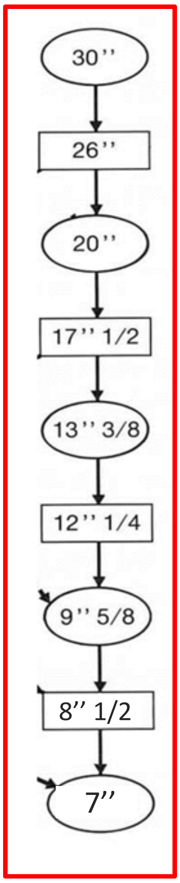


Example of well design (10 of 10)

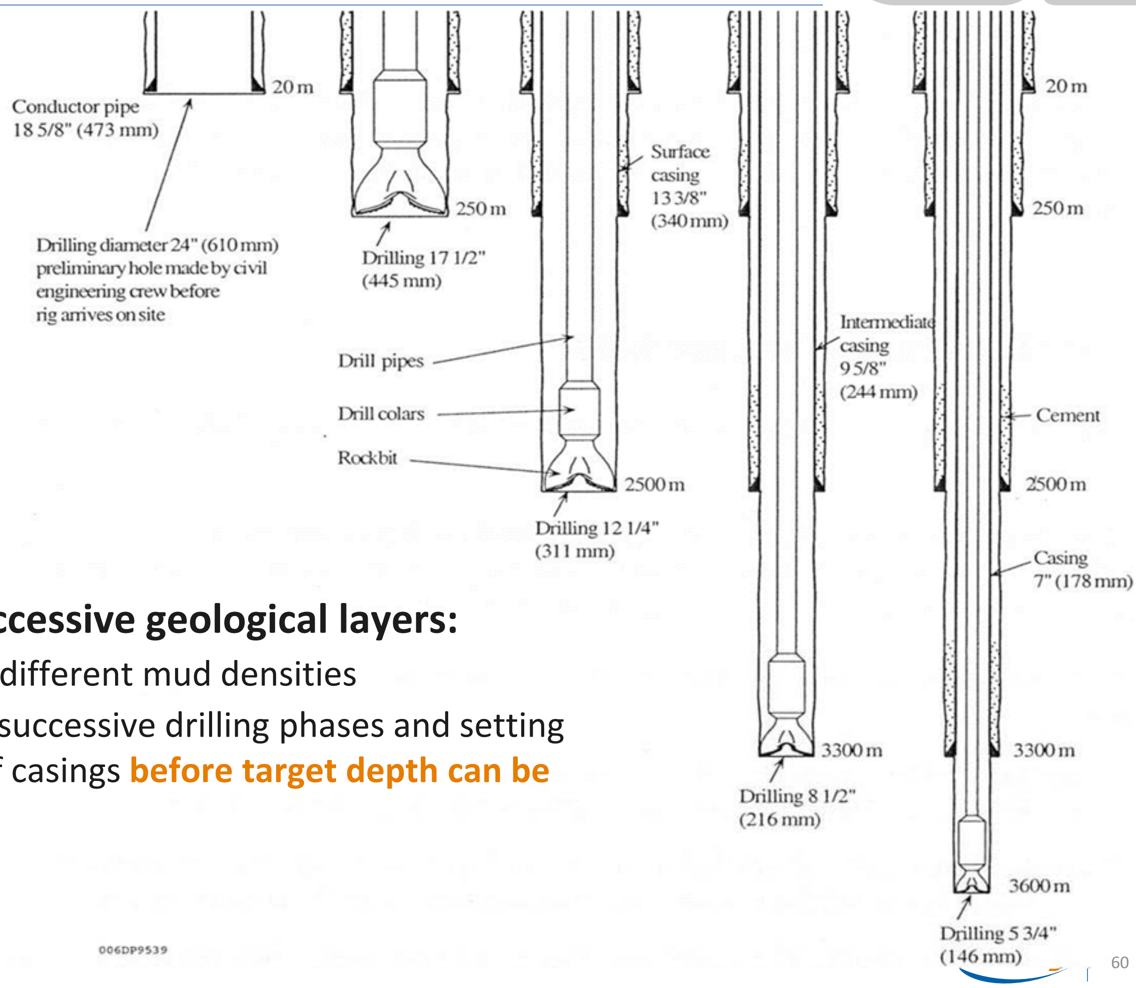


Casing design





Well engineering



- **Drilling of the successive geological layers:**
  - Usually requires different mud densities
  - Imposes several successive drilling phases and setting several strings of casings **before target depth can be reached**

006DP9539

Drilling/testing costs

- **Exploration costs**
  - (seismic, G&G studies)

WELL - DRILLING COSTS

- **Well equipment * & consumables**
  - (* well tangibles: e.g. casings, wellhead, …
  - (consumables: drilling bits, mud products, fuel …

  Mainly well depth dependent
- **Well Service contracts**
  - (drilling unit (rig)
  - (Service Companies (logging, cementing, …)

  Well duration dependent
- **Logistics facilities**
- **Personnel for supervision**
  - (Oil-Company personnel)
- **Insurances**
- **Contingencies**
- **WELL – TESTING COSTS (if any DST operations)**

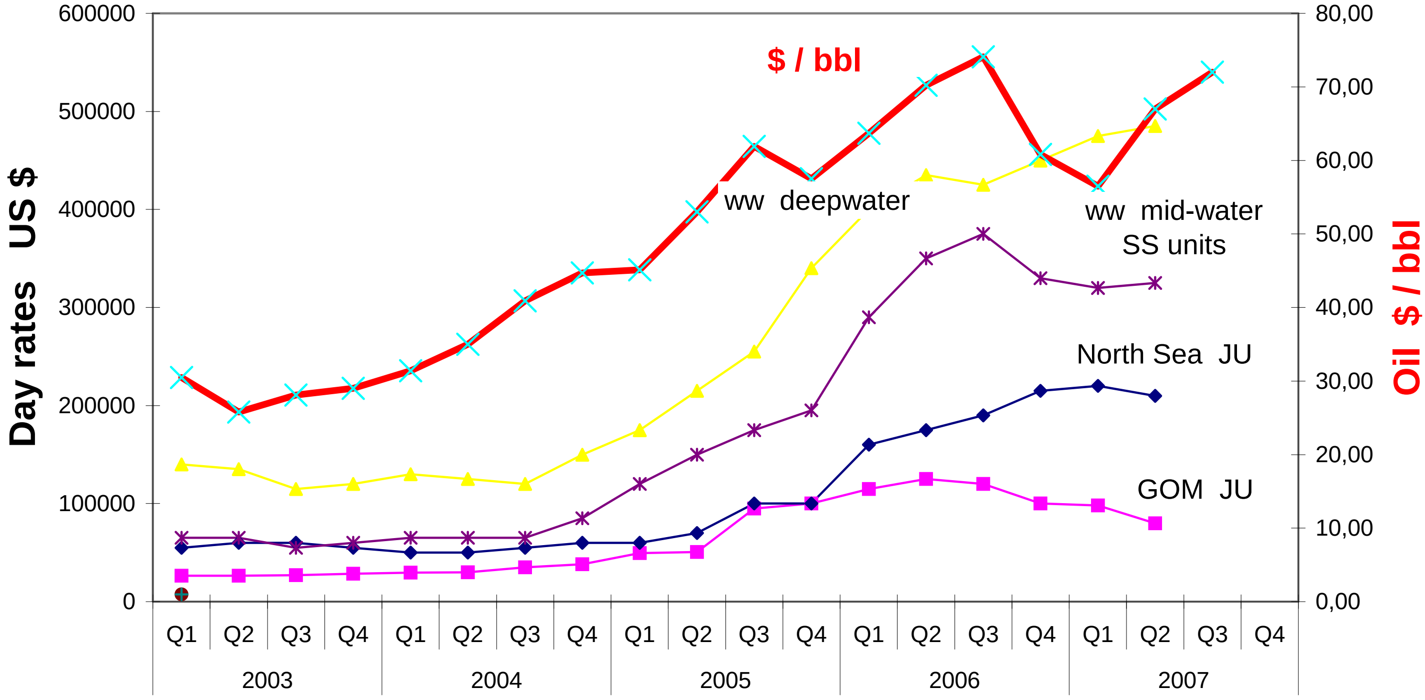
Drilling/testing costs: estimating well costs

	Rig rental costs *(indicative only)*	Operational daily costs *(indicative only)*
Land rig	30 to 45 K$ / d	70 to 100 KUS$/d
Drilling barge	45 to 100 K$ / d	130 to 150KUS$/d
Tender rig (conventional)	50 to 120 K$ / d	140 to 180 KUS $/d
Jack Up	100 to 250 K$ / d	200 to 300 KUS$/d
Semi-submersible		
(5000 < WD < 7500 ft)	200 to 250 K$ / d	250 to 350 KUS$/d
Drillships		
(5000 < WD < 7500 ft)	250 + K$ / d	330 to 400 KUS $/d
(7500 < WD < 10 000 ft)	+/- 450 K$ /d	550 to 600 KUS$/d

Figures vary with the type of contract (short/long term), market conditions, geographical area, …

Drilling/testing costs: estimating well costs

MODU day rates (2003 – Q2/2007)

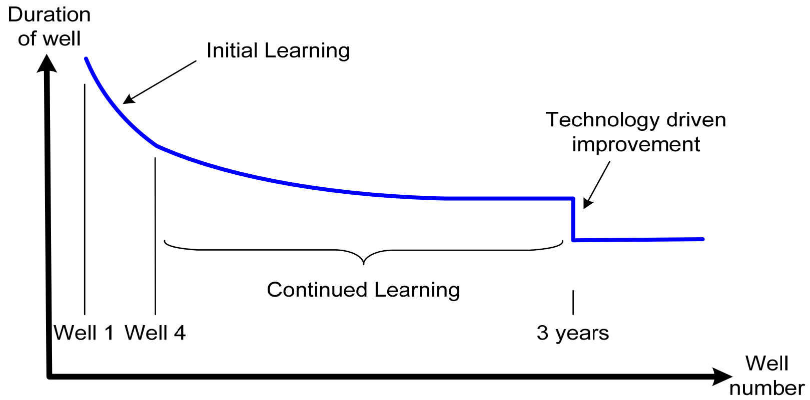


MODU: Mobile Offshore Drilling Unit

Estimating well costs

Learning curve effect

- **3 types of performance improvement during the drilling campaign**
  - Initial fast learning (debugging)
    - + 10 to 50 % factor for the first few wells
  - Continued learning from experience (optimization)
    - Performance trends to initial P25 value
  - "Technology" improvement
    - New bits, drilling motors, techniques, …



For a large campaign, learning curve can have a significant impact on Drillex

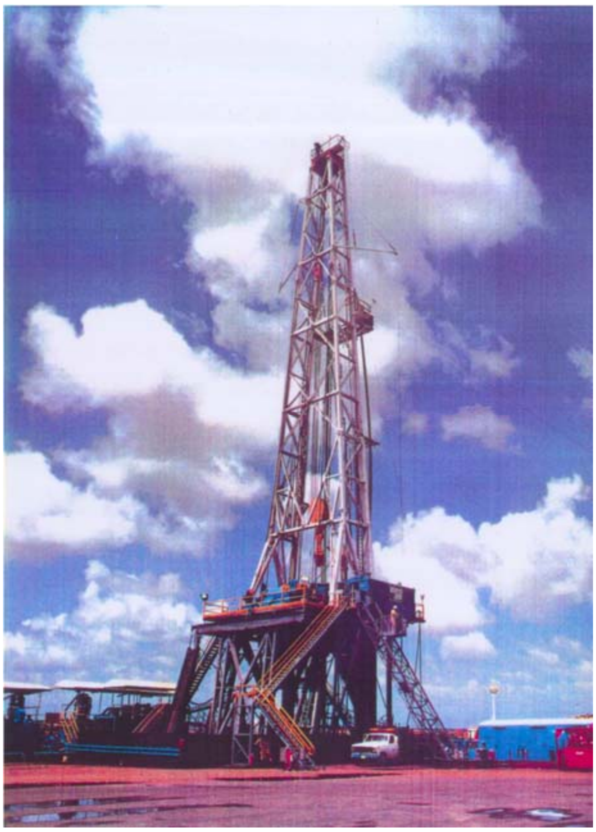
Drilling Units (the Rigs)

Main functions of a drilling rig

Rig types

Rig types

Land rig

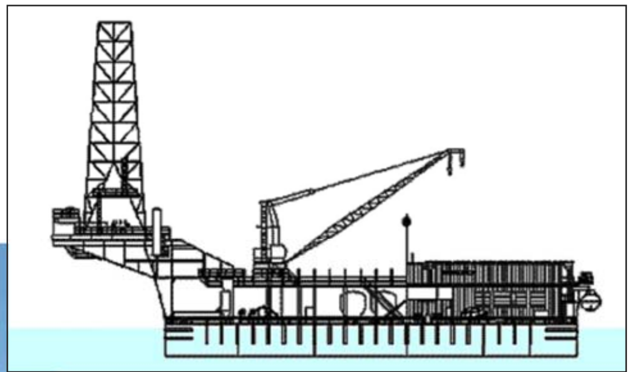


- Contrary to a mast, a derrick has to be erected piece by piece
- It is essential to check the verticality & centralization of the mast with the well

Swamp barge – Inland barge (Submersible)

Swamp barges are moved and positioned on location in floating condition, then ballasted to lay down on bottom (water depth of a few meters) to drill

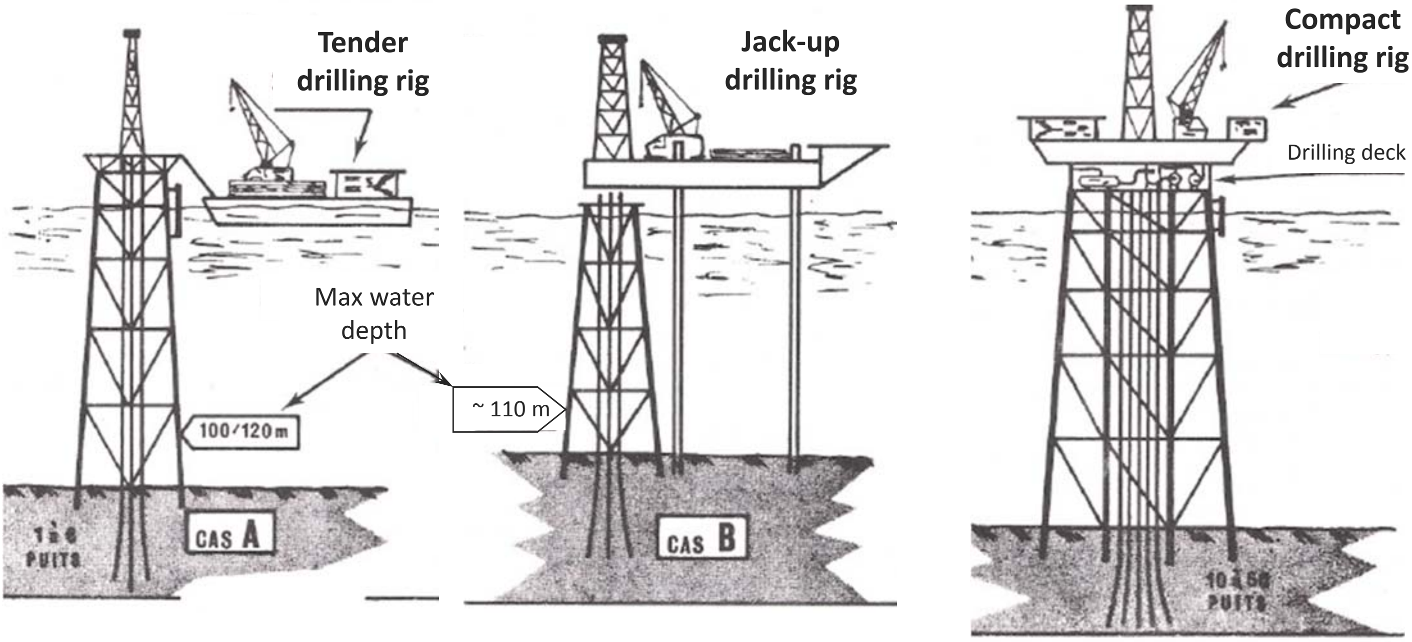
Barge: Maracaibo type



Floating barge with all the drilling equipment, including the derrick on a cantilever.

Working on a jacket

Drilling units to drill on fixed platforms



Drilling rig(s) on Wellhead Platform

Jack-up rig

Jack up (stand alone drilling)

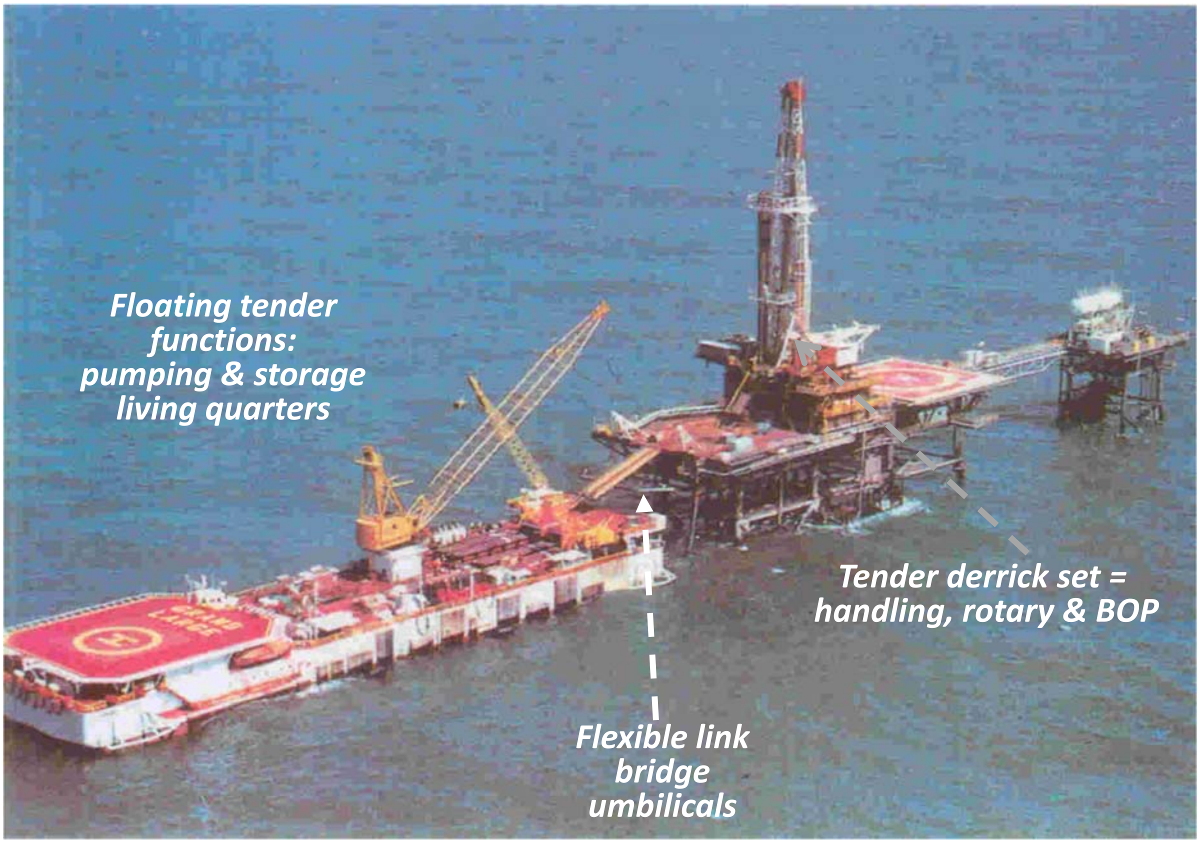
Exploration – Stand alone operation

Tender assisted drilling (TAD mode)

Functions:
hoisting
rotary
safety

Functions:
pumping
power
+ living quarters

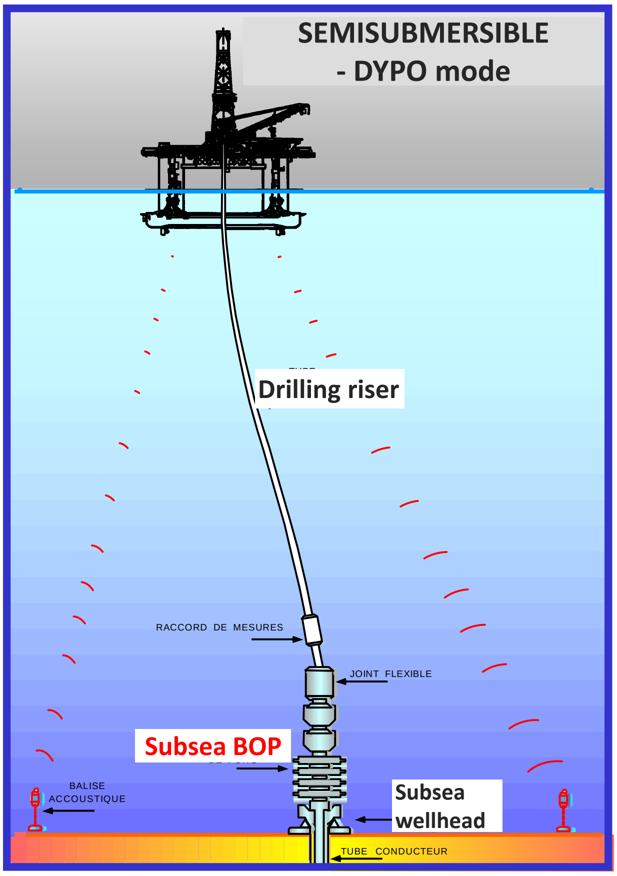
Tender assisted drilling (TAD mode)



Floating rigs

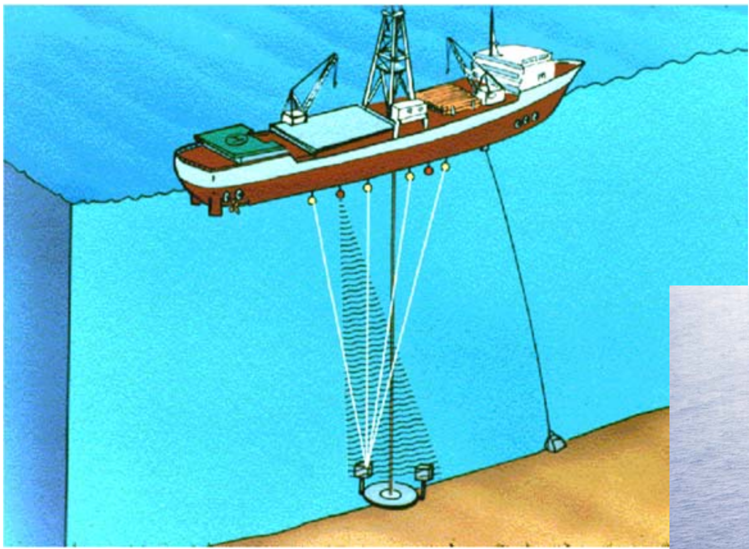
Floating platform motions

Semi-Submersible – Floating drilling unit



Drill ship

Dynamic positioning drillship



Variable deck loads are more important on a drillship than on a semi submersible (relative positions of barycenter & metacenter)

Key points to keep in mind

- **Main functions of a drilling rig**
  - Hoisting
  - Rotation
  - Mud circulation
  - Well control

- **Mud circulating system**
  - Closed system
  - Mud pits ➔ HP pumps ➔ Standpipe/flexible hose ➔ Swivel ➔ Drill string ➔ Bit ➔ Openhole/casing to drill string annulus ➔ Mud ditch ➔ Shale shakers ➔ Mud treatment equipment ➔ Mud pits

- **Offshore rig types and field of application**
  - Swamp barge: very shallow water (swamp area), fixed, surface wellhead
  - Jack up: up to ~ 110 m WD, fixed, surface wellhead
  - Platform rig: modular type installed on fixed development platform
  - Tender: mostly to drill development wells from a fixed platform
  - Semi submersible: up to ~ 1000 m WD, floating, subsea wellhead
  - DP drillship: up to ~ 3000 m WD, floating, subsea wellhead

Well Construction

Main steps of well operations (typical)

EXPLORATION/APPRAISAL

Rig moving in

↓

Well spudding
Drilling/casings to target

↓

Logging

↓

Testing *

↓

Plug & Abandon (P & A)

↓

Rig moving out

DEVELOPMENT

Rig move from previous well slot

↓

Well spudding
Drilling/casings to target

↓

Logging *

↓

Completion

↓

Rig move to next slot

↓

Connect flowline

*: optional

Content

- Well safety barriers
- Drilling and casing sequence of operations
- Drilling mud
- Casing cementing
- Drill bits
- Drill string
- Drilling problems
- Logging operation
- Mud logging operation

Well safety barriers

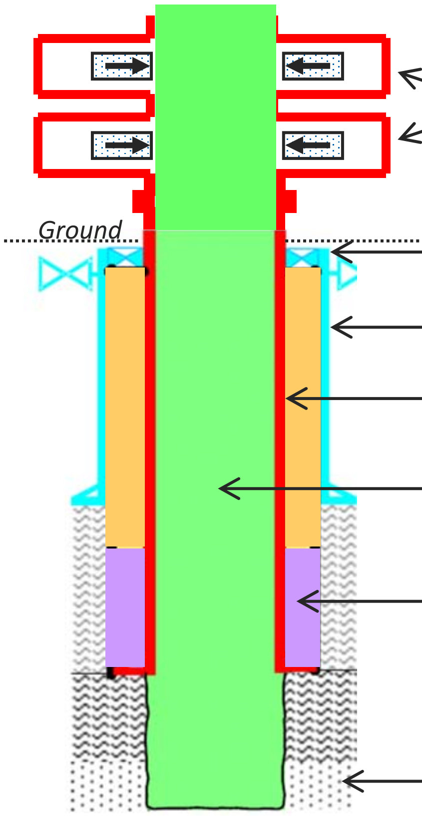
Two safety barrier rules

- **During drilling and well activities there shall be at all times at least two independent and tested well barriers after the surface casing is in place**
- **If a barrier fails, no other activity shall take place in the well than those intended to restore the barrier**
- **Two types of safety barriers:**
  - *« Passive »:*
    - Casing, tubing, packer, wellhead body, static wellhead seal, …
    - Cement plug, cemented annulus
    - Fluid column
  - *« Active »:*
    - Blow Out Preventers (BOP)
    - Valves on drilling string or tubing (Down Hole Safety Valve)
    - Valves on wellhead, X-Mas tree

Example (drilling phase)

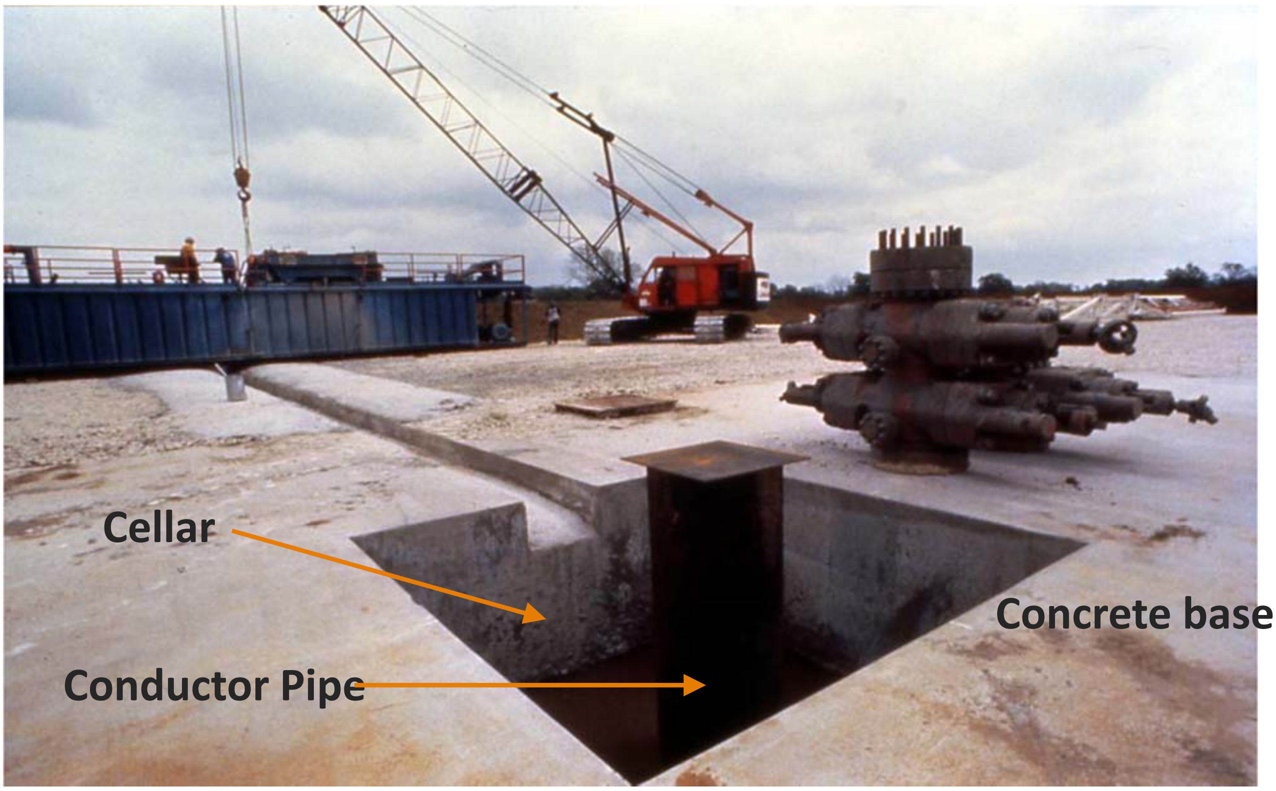
- **Two barriers on the external leak path (inside the last casing set):**
  - Drilling mud
  - Blow out preventers

- **Two barriers on the internal leak path (outside the last casing set):**
  - Cement
  - Wellhead annulus seal



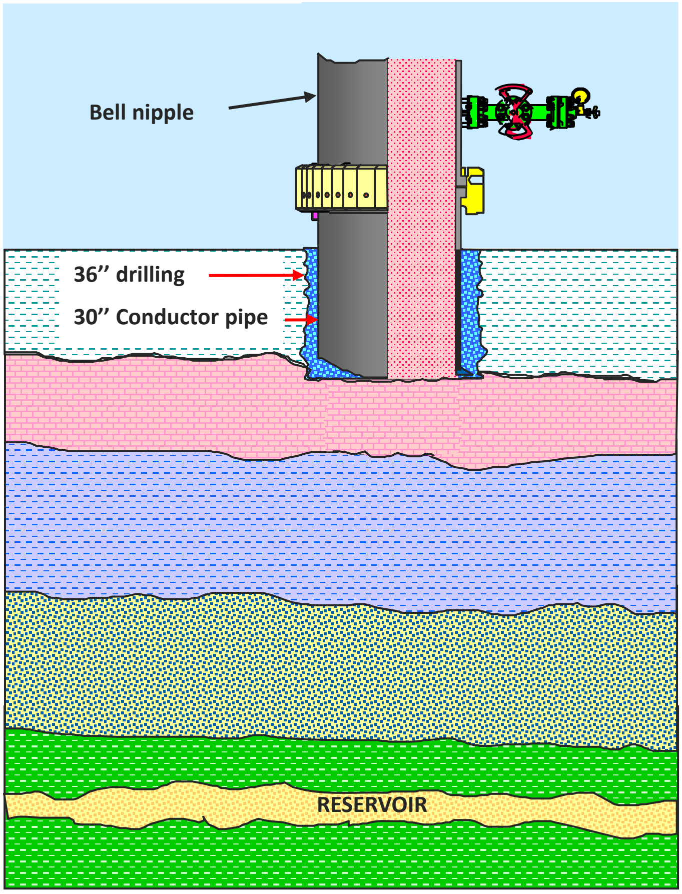
Contents

Well construction (onshore well)



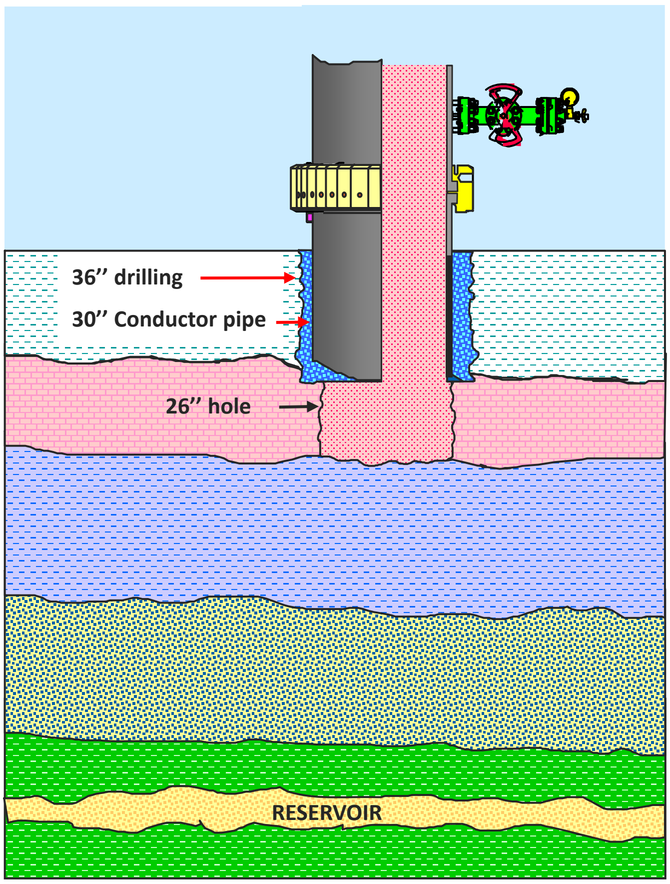
Concrete base: rig support & wellhead cellar

36'' drilling phase / 30'' conductor pipe (onshore well)



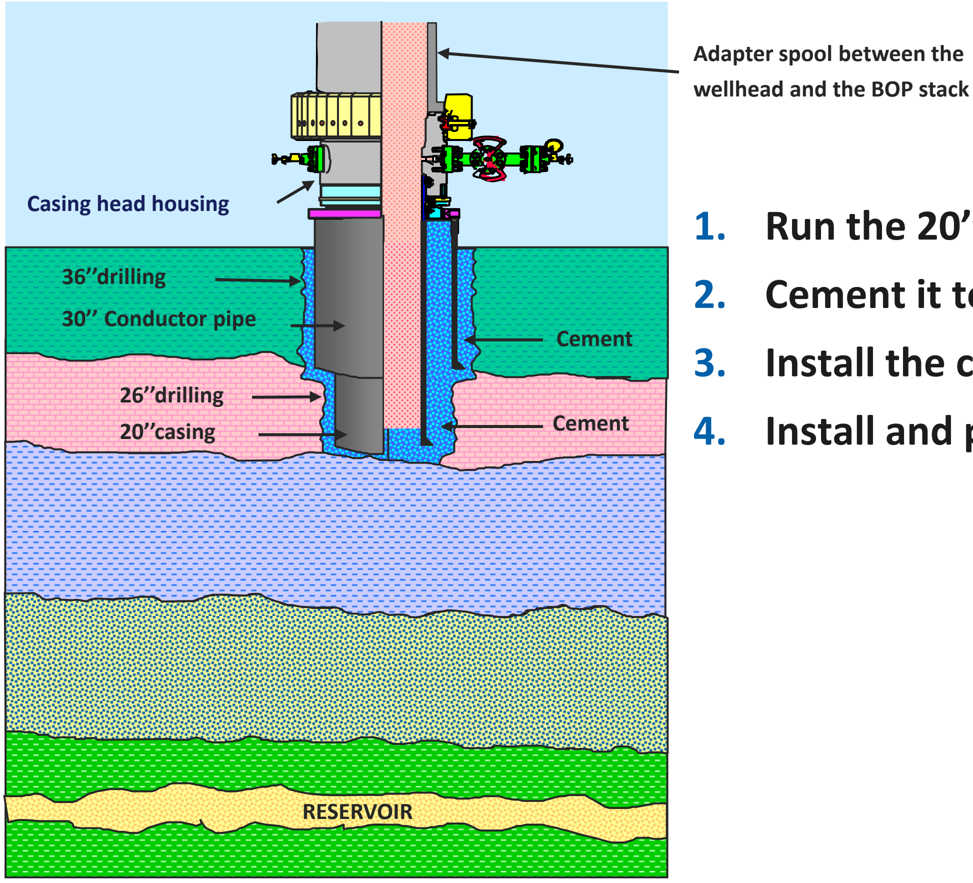
- **The conductor pipe can be:**
  - Set by the civil works: onshore
  - Driven using a hammer: onshore / offshore
  - Run in hole and cemented in a drilled hole (36'' diameter): offshore

26'' drilling phase (onshore well)



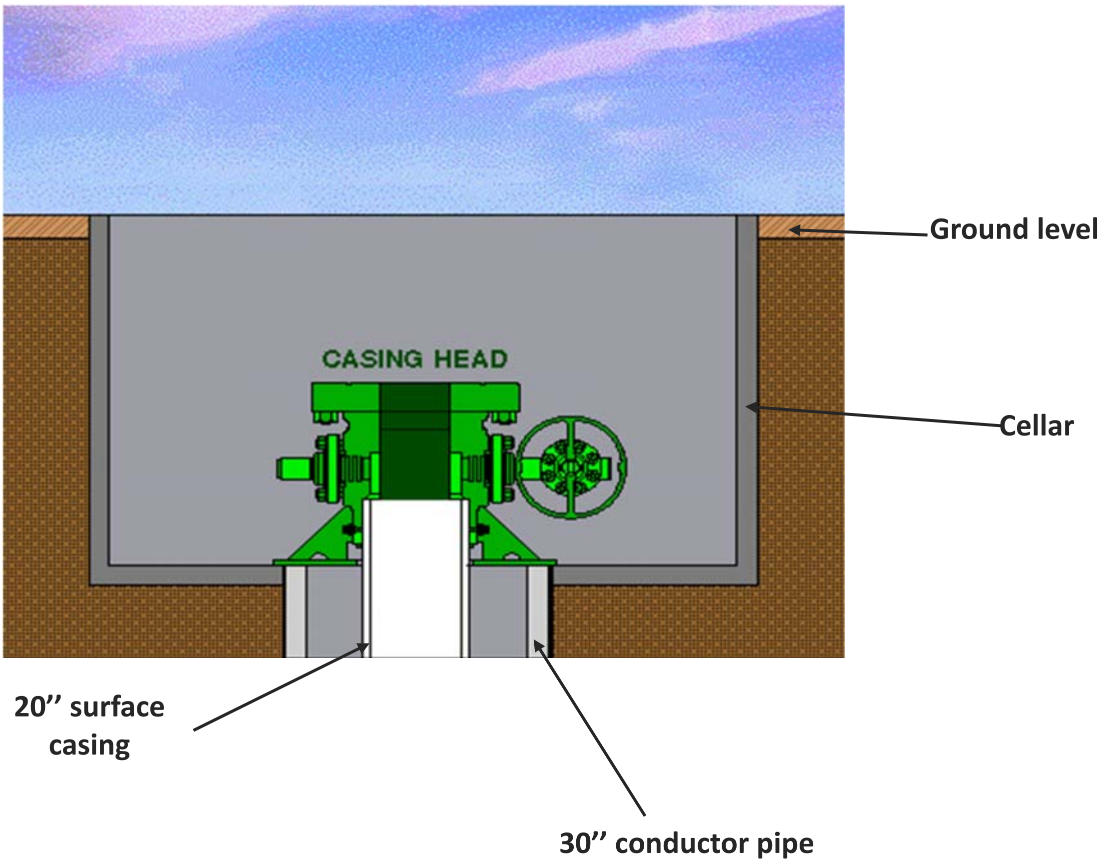
- **In the first drilling phase the only safety barrier is the drilling mud (no BOP)**
- **In case of risk of shallow gas, a gas diverter system is used on surface**
- **The 26'' hole is drilled to the surface casing setting depth**
- **The surface casing is generally cemented to surface (or to mud line for offshore well)**

20'' casing (onshore well)

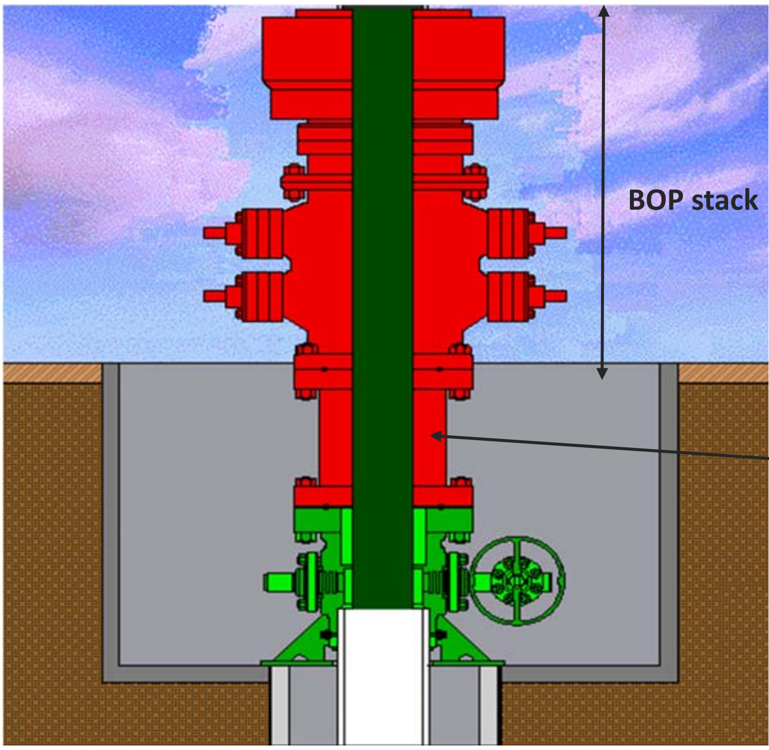


1. Run the 20'' surface casing
2. Cement it to surface
3. Install the casing head housing
4. Install and pressure test BOP stack

Installing the 20'' casing head housing (onshore well)



Install and pressure test the BOP stack (onshore well)

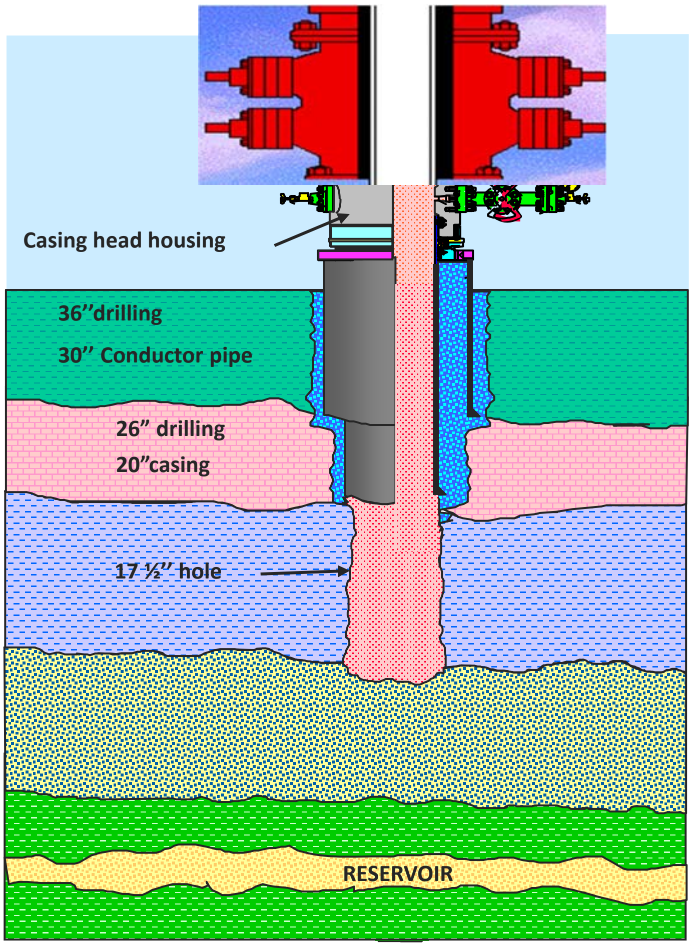


BOP: Blow Out Preventer

Adapter spool between the wellhead and the BOP stack

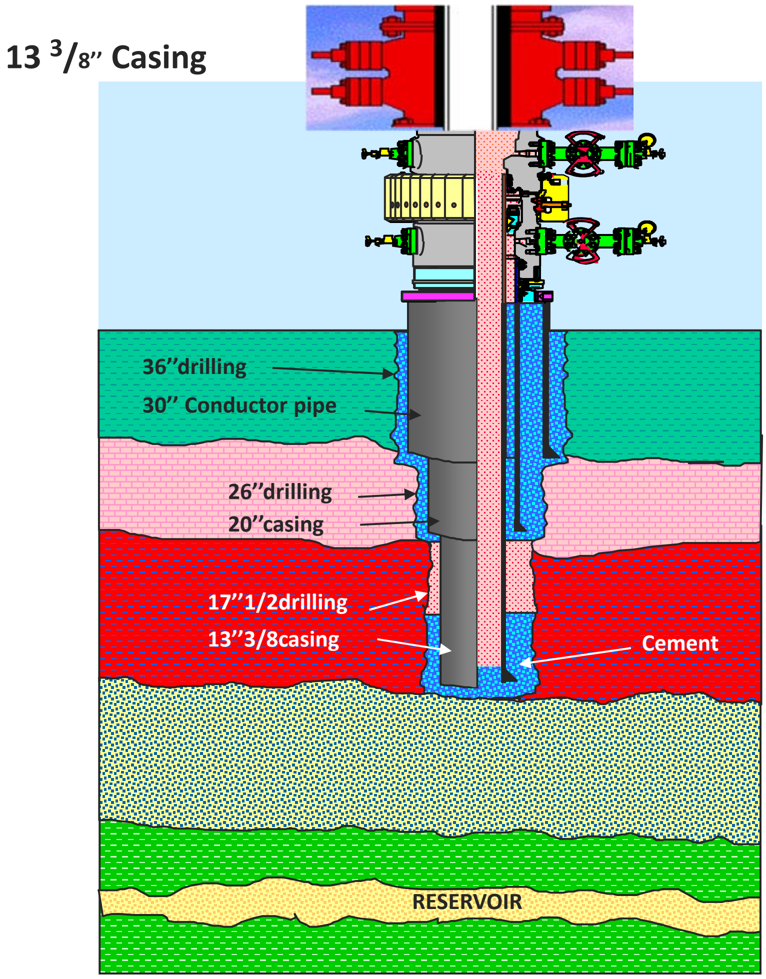
From this point, there are 2 safety barriers in the well: Mud and BOPs.

17 ½'' drilling phase (onshore well)



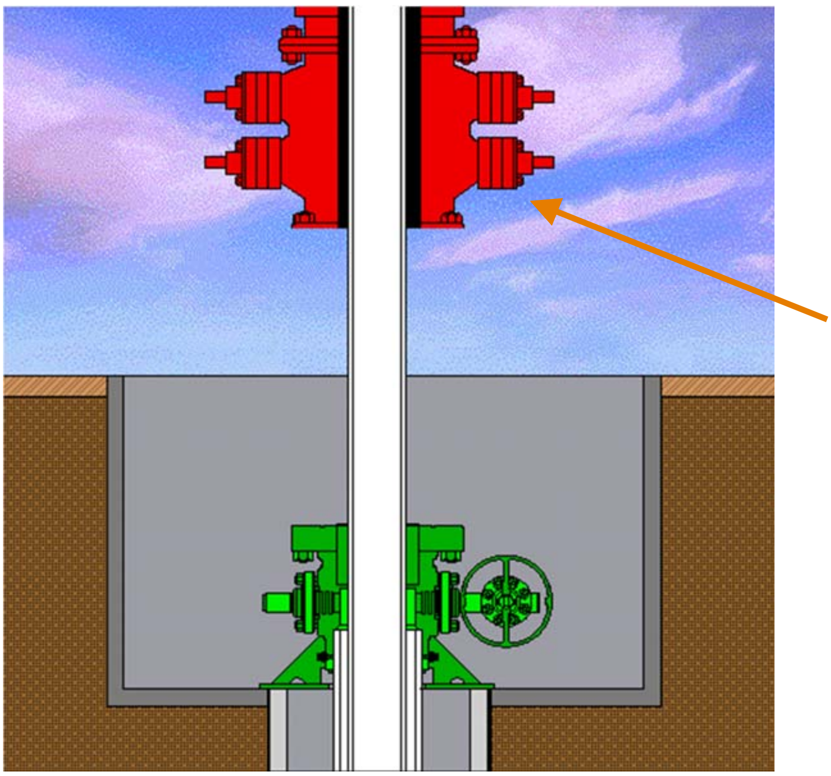
1. **Drill out the cement and the 20'' casing shoe (change to new mud if required)**
2. **Drill the 17 ½'' hole to the planned 13 3/8'' casing setting depth**
3. **Run and set the 13 3/8'') intermediate casing**

End of 17 ½'' drilling / 13'' 3/8 casing (onshore well)



After running the 13 ⅜ casing to the setting depth it is cemented in place

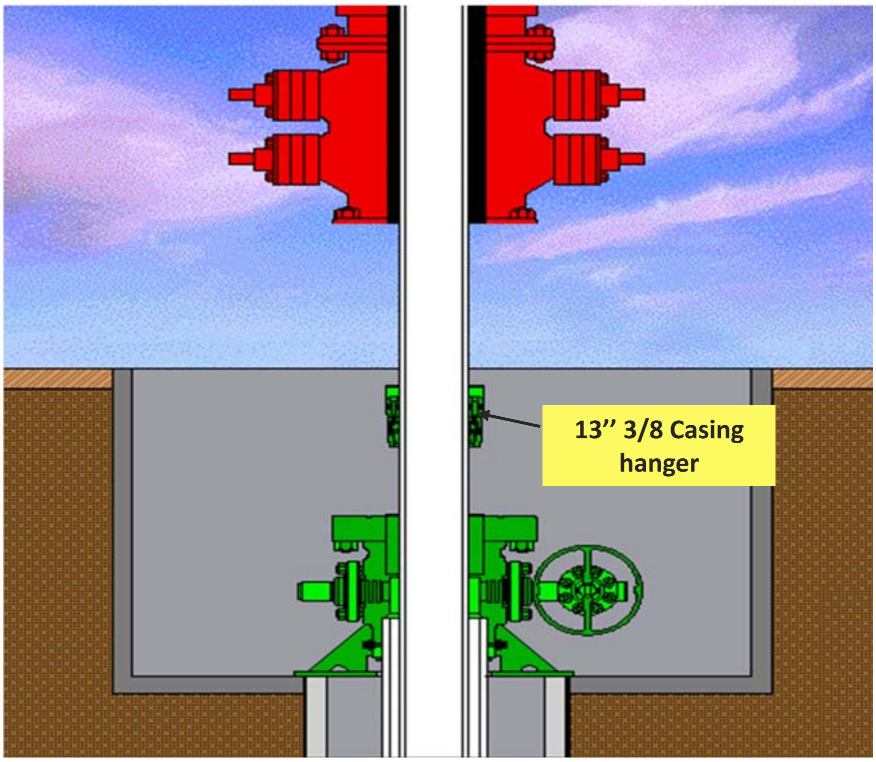
13 3/8'' casing (onshore well)



After cementing the 13 ³/8'' casing the BOP stack is lifted to prepare for hanging the casing in the casing head housing.

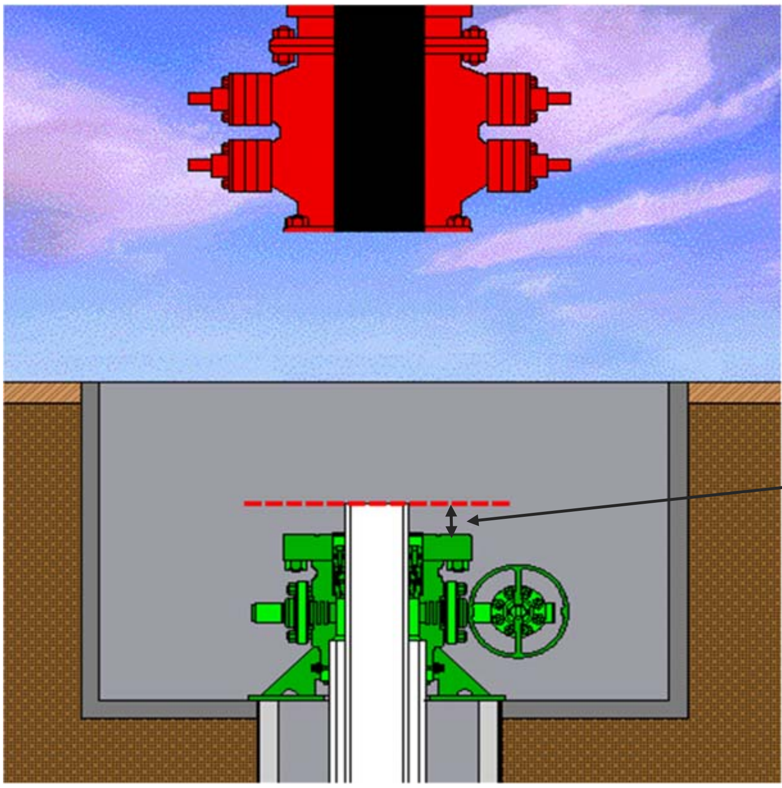
Note: During this operation the well is secured with 2 safety barriers: Cement + Mud column

Install the 13 3/8'' casing hanger (onshore well)



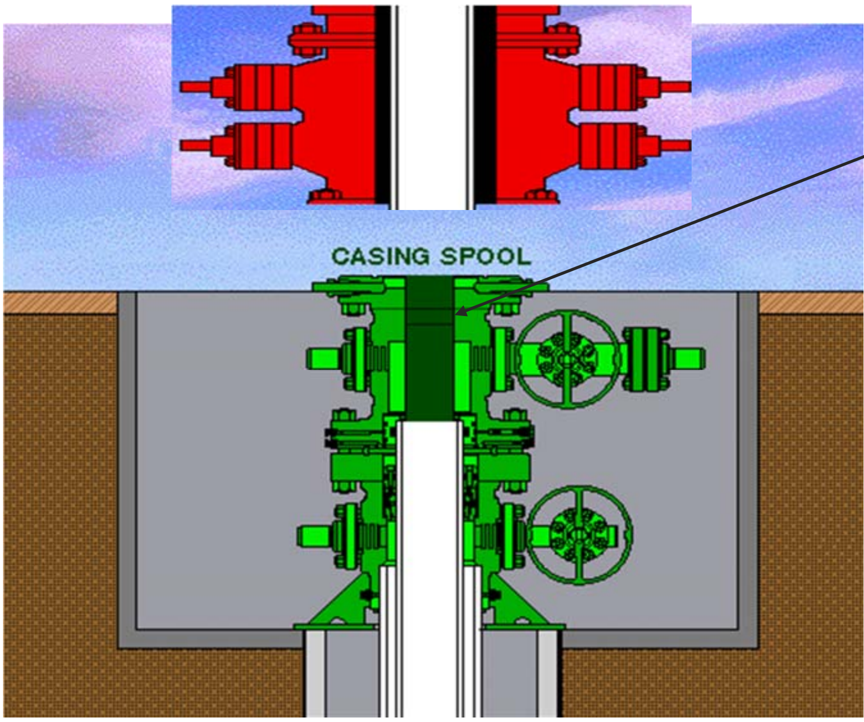
Setting the casing hanger

13 3/8'' casing hanger (onshore well)



The 13'' 3/8 casing is cut in order to install the casing spool that will receive the next casing hanger

Casing spool installation (onshore well)

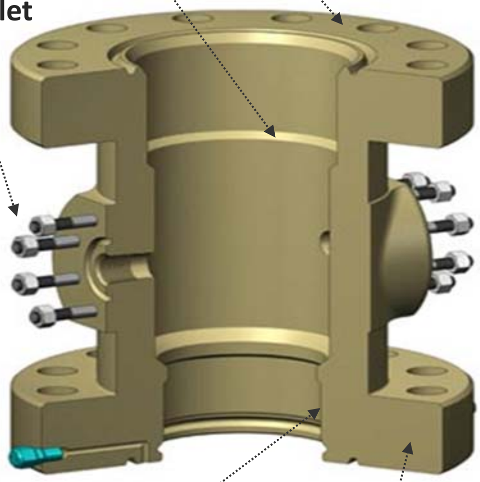


Receptacle for next casing hanger

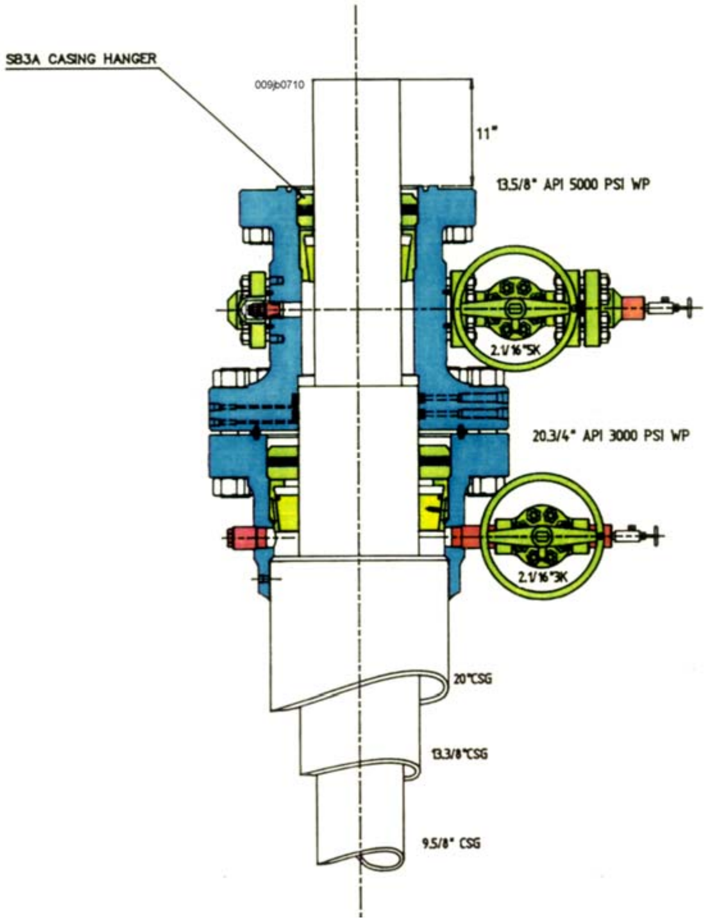
20'' x 13'' 3/8 annulus seal

Casing spool

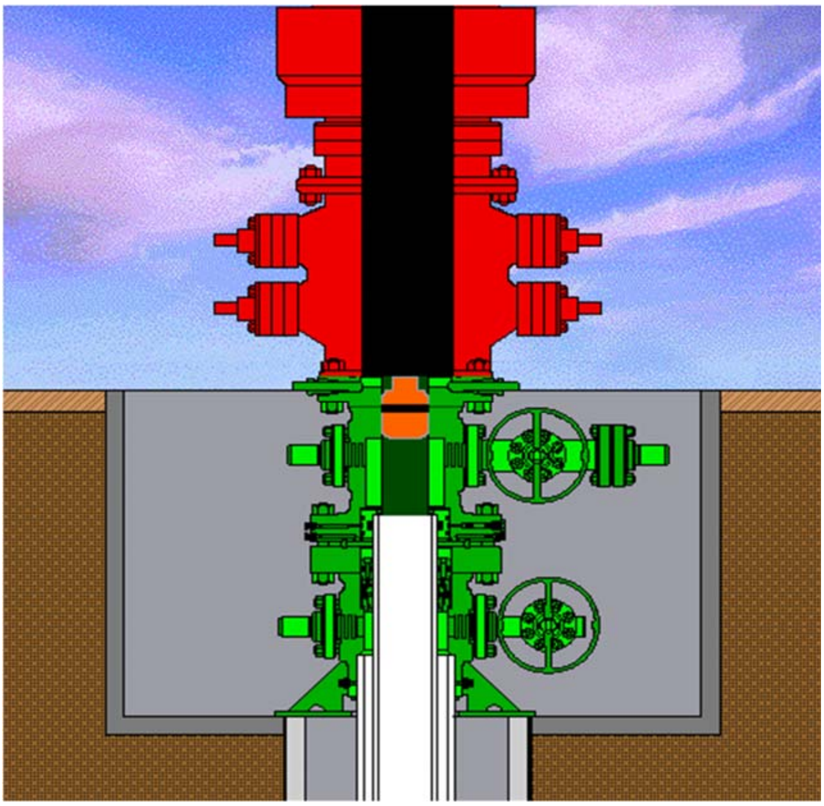
- **Supports one string of casing**
- **Includes:**
  - Two flanges (top and bottom) of different sizes and service pressures
  - One internal conical profile or shoulder to receive the casing hanger
  - One cylindrical profile on bottom to receive a sealing element to seal the casing x casing annulus
  - Flanged side outlets to provide access to casing x casing annulus



9 5/8'' casing hanger

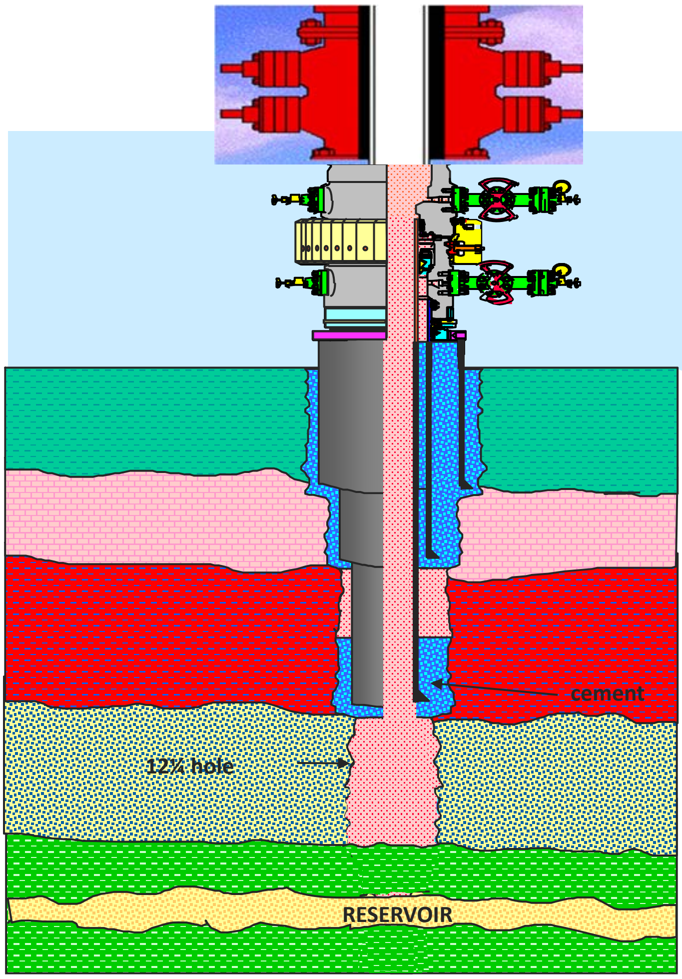


Install and pressure test the BOP stack (onshore well)

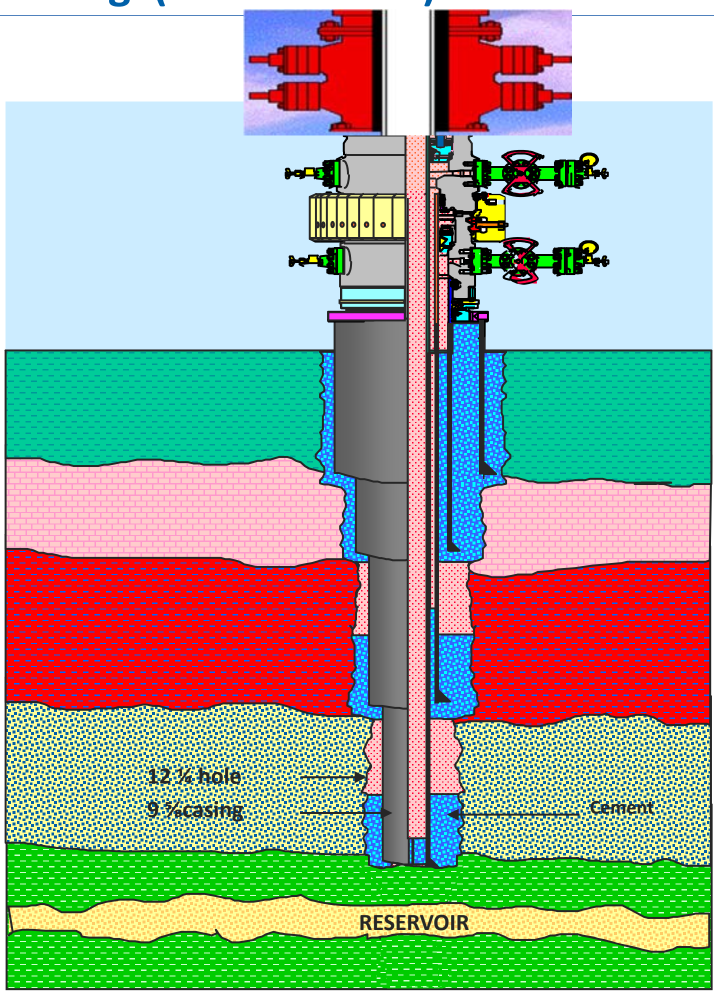


The BOP stack is pressure tested before drilling out the cement and the casing shoe at the bottom

12 ¼ drilling phase (onshore well)

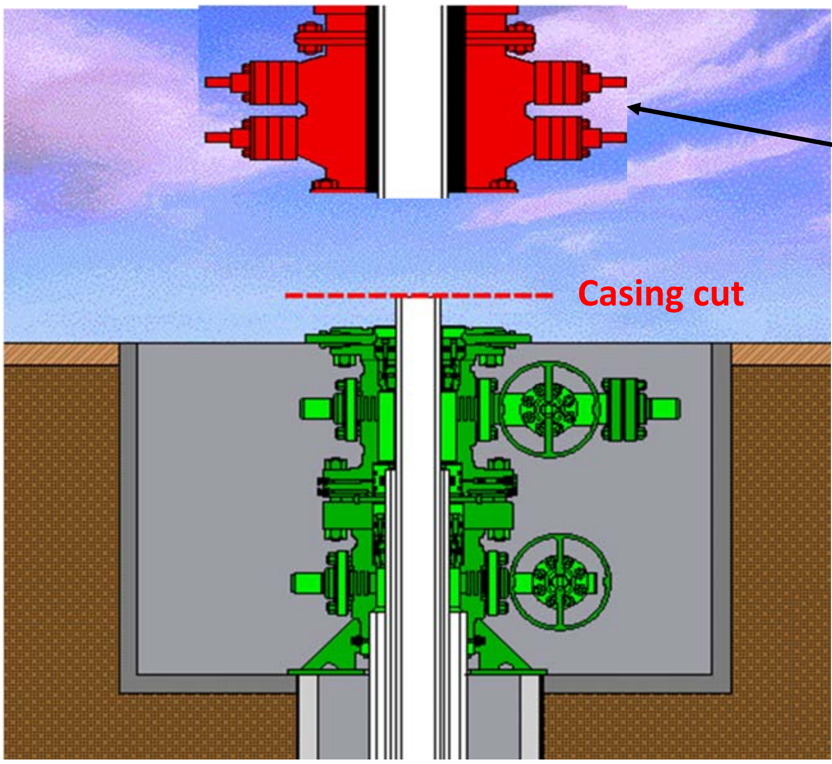


9''5/8 casing (onshore well)



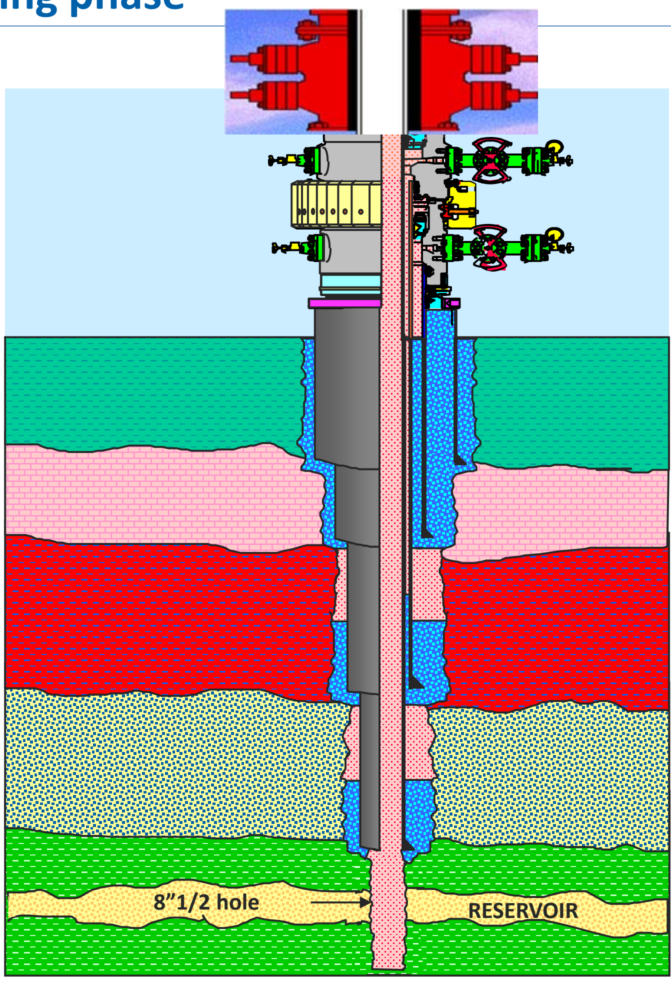
RIH the 9 ⅝ casing, cement and hang in the casing spool on surface

9 5/8'' casing hanging



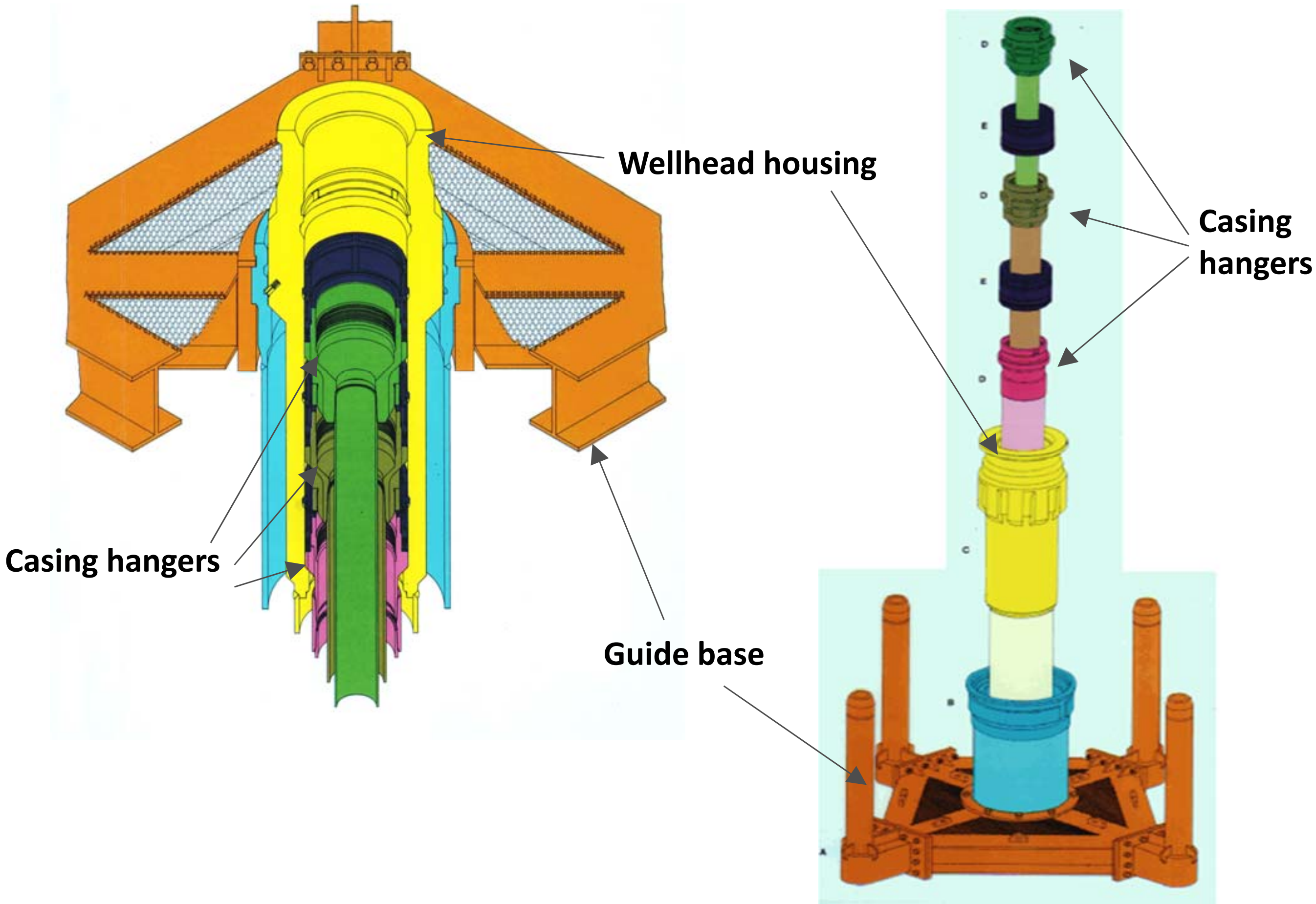
- The BOP stack is lifted up
- The casing is suspended with a casing hanger and then cut to receive a casing spool or a tubing head according to the well design

8 ½'' drilling phase



- Drill the 8½ hole
- RIH and cement the 7'' production casing

Subsea drilling wellhead

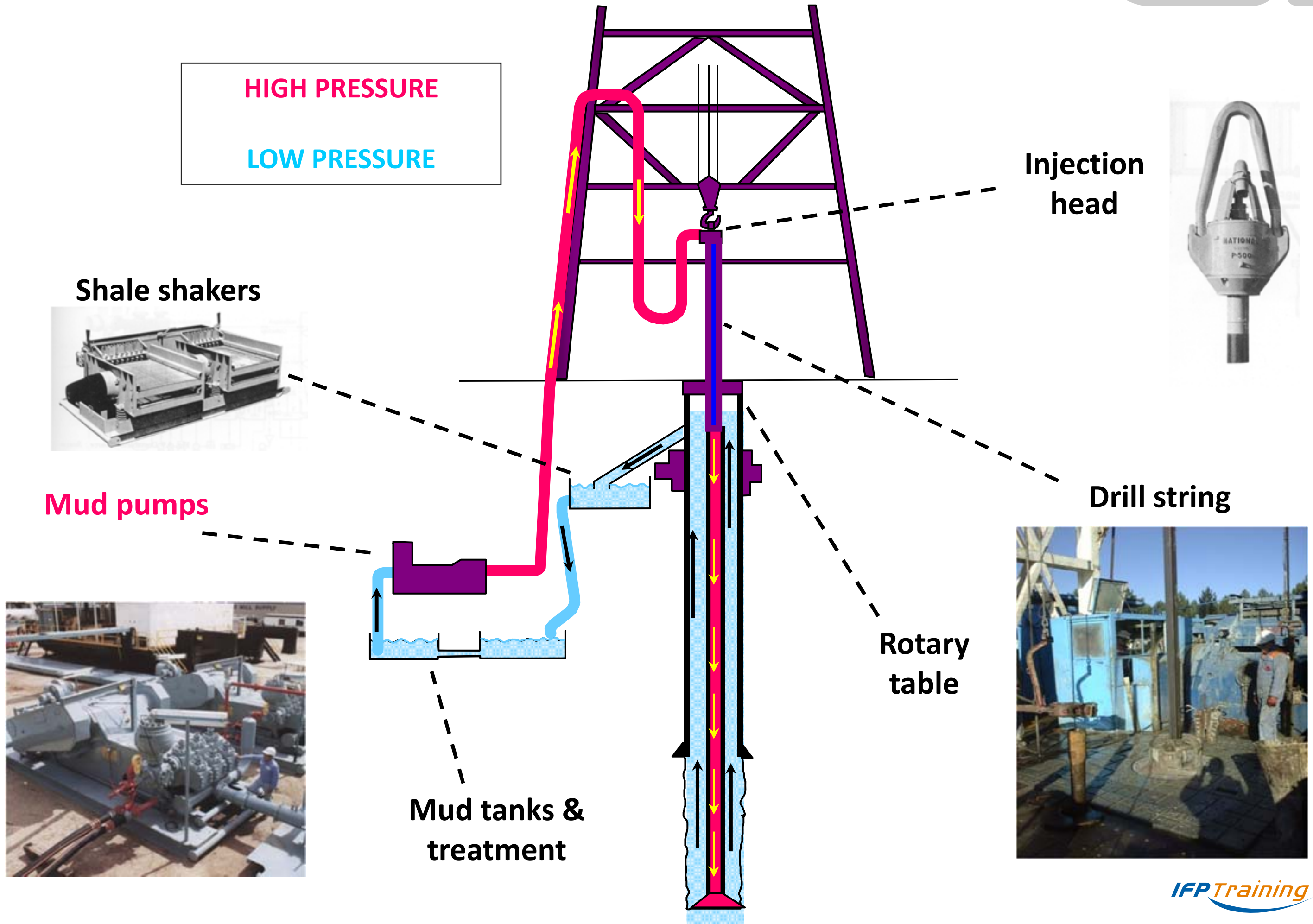


Key points to keep in mind

1. **Drilling phases**
   - Drilling a well is done by steps called "drilling phases"
   - For an onshore or surface well, a drilling phase typically includes:
     - Drilling new formation from the previous casing shoe depth to the next casing shoe depth.
     - Perform data acquisition in open hole as per program
     - Run and cement casing string
     - Set and seal casing in wellhead
     - Install new wellhead spool for the next casing string
     - Pressure test BOP stack
     - Drill out float collar and casing shoe
   - For an offshore subsea well, the operations of setting and sealing the casing in the wellhead differs from a surface well since the wellhead and BOP stack are located at the seabed
   - Typical drilling phases are: **36''** (for 30'' CP), **26''** (for 20'' casing), **17''** (for 13 3/8'' casing), etc.
2. **Wellhead (surface well)**
   - The wellhead assembly consists in:
     - **Wellhead housing:** installed at the top of the surface casing, is supported by the conductor pipe
     - Several **casing spools** (nb depends on the drilling program): installed one on top of the other above the wellhead housing, connected together by flanges, they receive inside a string and casing that is hung by a **casing hanger**
     - **Casing hanger** for each string of casing, includes a **sealing element** to seal the annulus space between the newly set casing and the previous one.

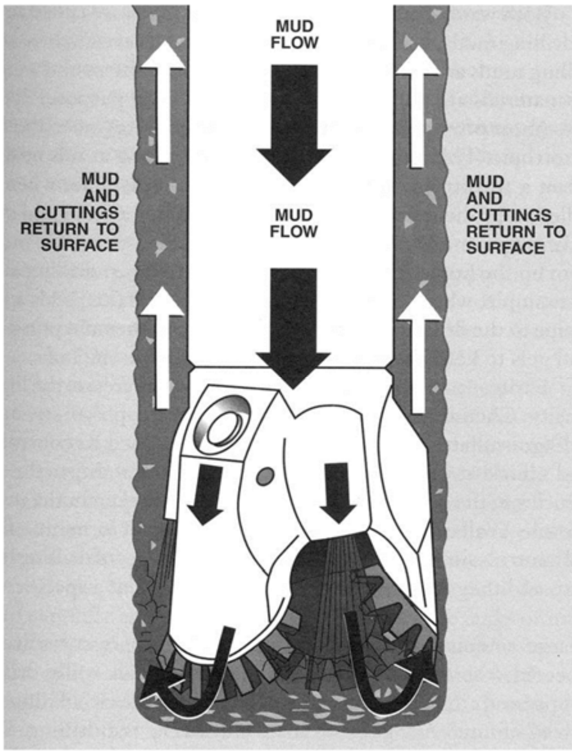
Contents

Drilling mud circulation

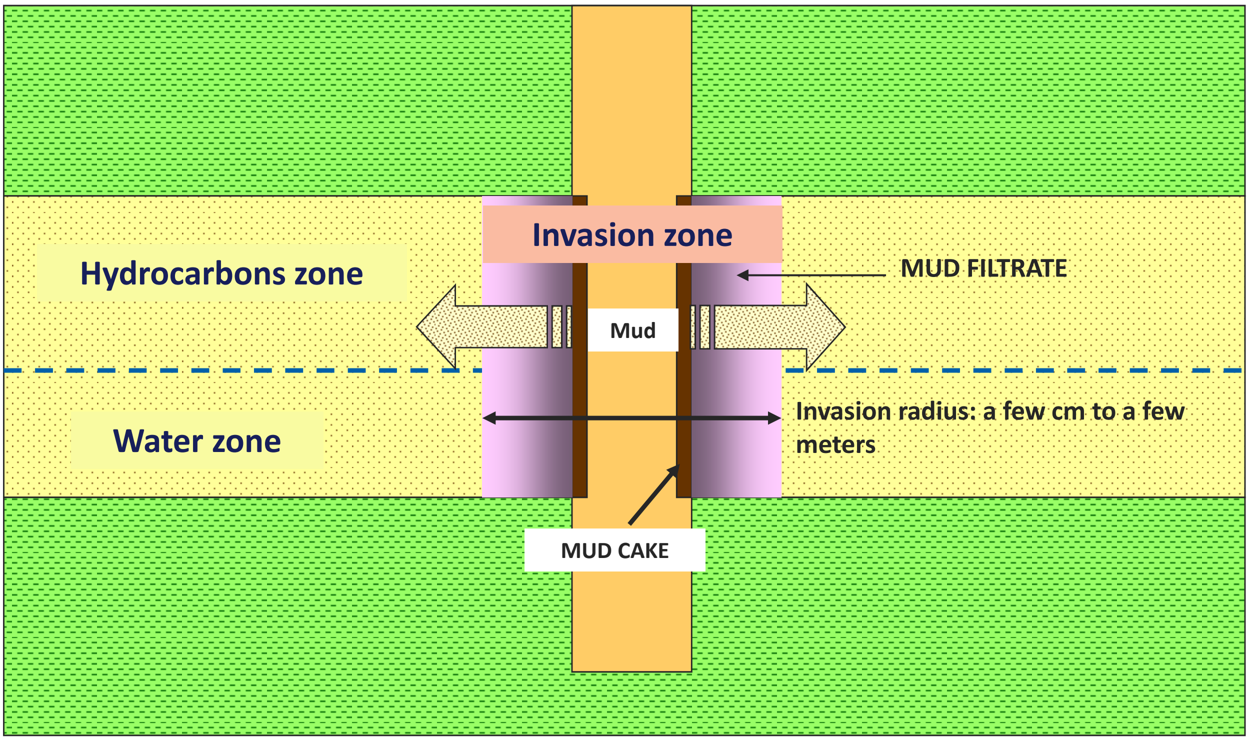


Functions of the drilling fluid

- **To lift formation cuttings to surface**
  - Convey drilled cuttings and geological information to surface
  - Clean the hole
  - Prevent cuttings to settle in the hole when mud circulation is stopped
- **To control the subsurface fluid pressure**
  - Balance formation pressure and thus prevent formation fluid influx into the borehole
- **To cool down the drill bit and lubricate drill string**
- **To aid to formation stability**
- **To protect formation productivity**
- ***To provide hydraulic power to downhole motors or turbines when used***



Mud filtrate & cake

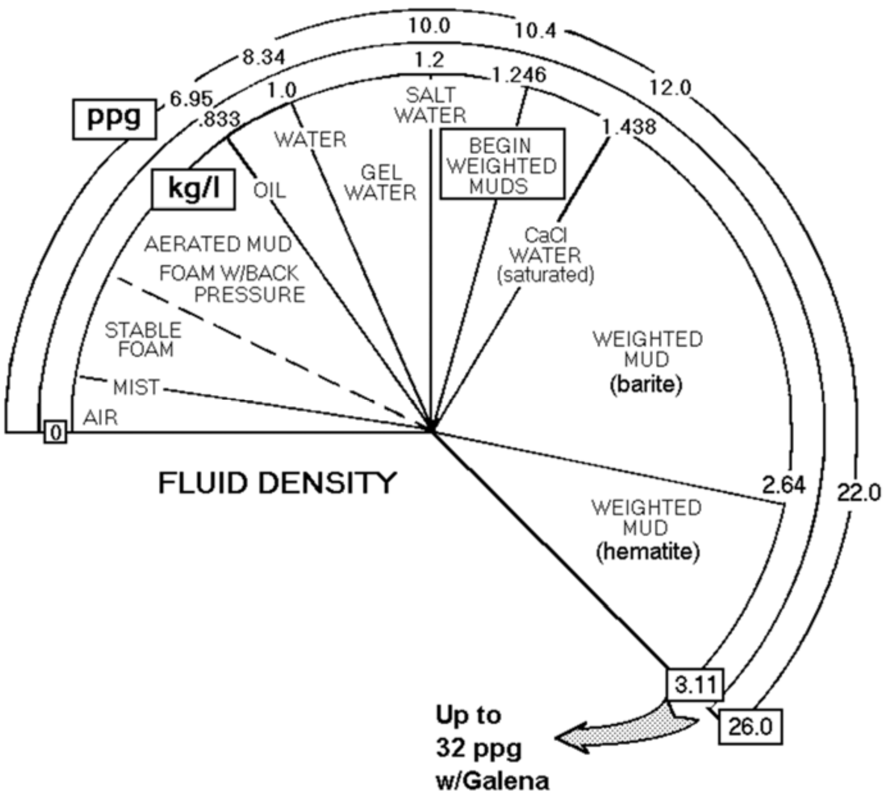


Mud filtrate invades the porous zones until a cake is formed and provides sealing

Types of drilling fluid

- **Drilling mud**
  - Solutions that contain suspended solids, and often other liquids or gases
  - The suspending liquid (base) forms a ***continuous phase***, with the suspended solids and other materials present as a ***discontinuous phase***
- **Water based mud (WBM)**
  - Bentonitic mud, salt saturated mud, mud to inhibate shales(KCl mud, gypsum mud, au glycol), polymer mud, etc.
- **Oil based mud (OBM)**
  - Oil content: 50 to 98%
  - Low Toxicity Oil Based Mud (LTOBM), use of synthetic oil
- **Air, foam (mixture air + water + foaming agent), aerated mud**
  - Potential application in depleted/low pressure reservoirs
- **Completion/workover fluids**

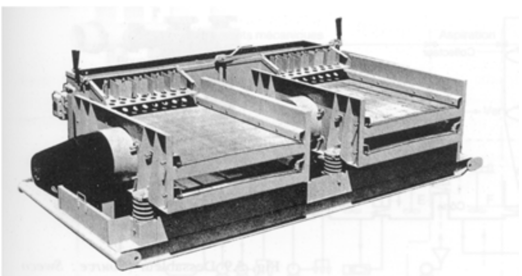
Mud weight



Drilling mud main characteristics

- **Density (mud weight)**
  - Balances the formation pore pressure and contains fluids in formation
  - Maintains wellbore stability
- **Viscosity, gel**
  - Carries the rock cuttings to the surface
  - Maintains solids in suspension (while circulation is stopped)
- **Filtrate**
  - Minimizes mud fluid invasion in the formation
- **Solid content**

Drilling fluids: mud treatment



Shale shakers

- **Mud is pumped through the stand pipe to the rotary hose, the swivel & the drill string.**
- **Cuttings are eliminated from the mud by shale-shakers.**
- **De-sanders, de-silters, hydro-cyclones and centrifuge progressively eliminate unwanted thinner solid particles from the mud.**
- **Gas is stripped by a degasser in case of "gas cut mud"**

Mud degasser

Hydro-cyclones

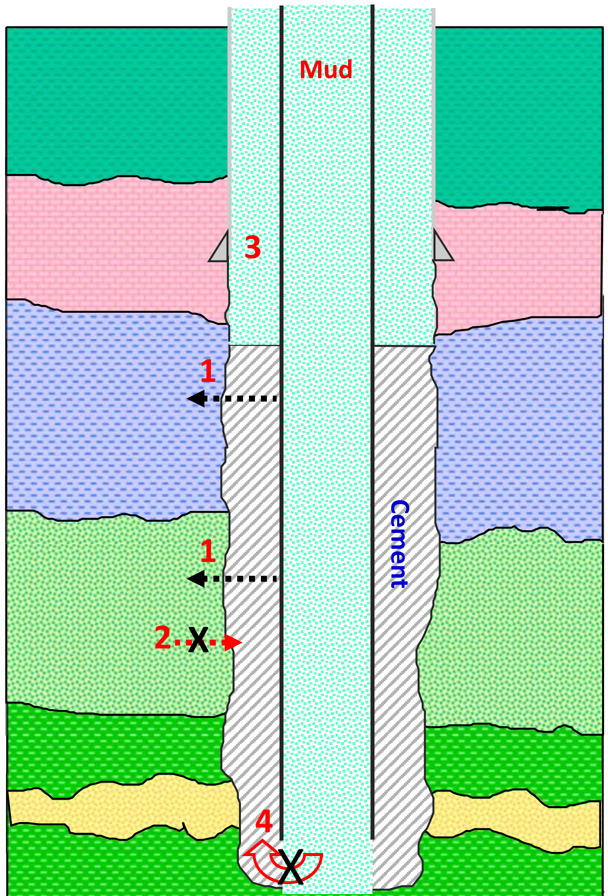
Centrifuge

1. **Main functions of the drilling mud**
   - Transports cutting to surface
   - Controls the formation fluid pressure
   - Cools down the drill bit & lubricate the drill string
   - Contributes to the formation stability
   - Protects the formation productivity
2. **Main types of mud**
   - Water based mud (WBM)
   - Oil based mud (OBM)
   - Air, foam (mixture air + eau + foaming agent), aerated mud
   - Completion/workover fluids
3. **Main characteristics of the drilling mud**
   - Density (mud weight)
   - Viscosity, gel
   - Filtrate
   - Solid content
4. **Mud treatment equipment**
   - Solid removal equipment: shale shakers, desander, desilter, centrifuge
   - Mud degasing: mud gas separator

Contents

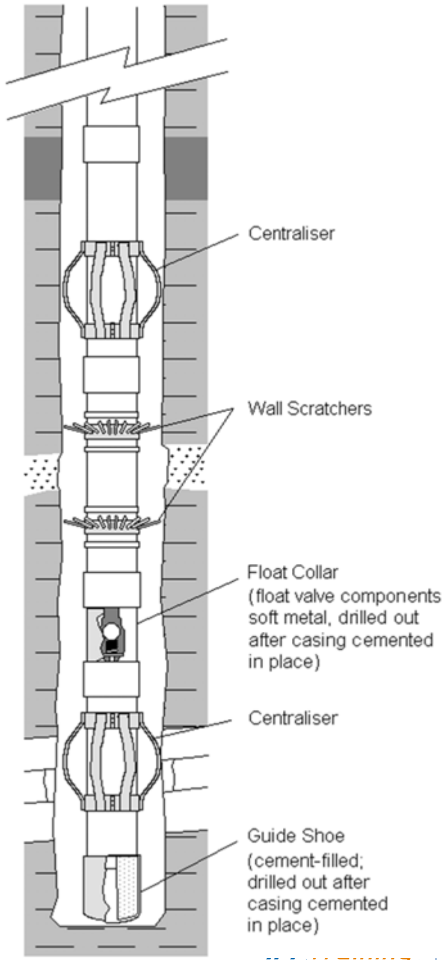
Objectives of casing cementing

1. To provide mechanical anchoring of casing string in formations (Transfers weight of casing string to formations)
2. To isolate reservoirs/formations located behind casing
3. To ensure annulus seal above reservoirs/formations
4. Tightness of annulus base
5. To prevent formation collapse and swelling (shale, salt, …)

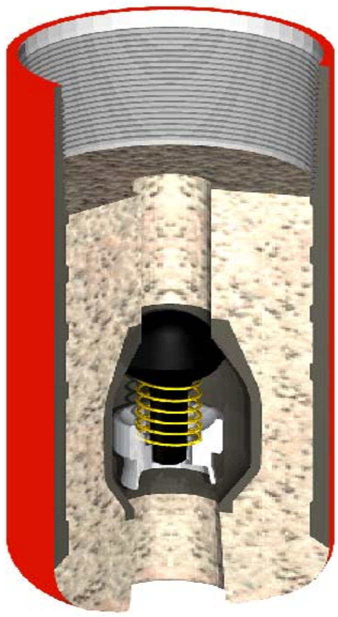


Casing cementing equipment

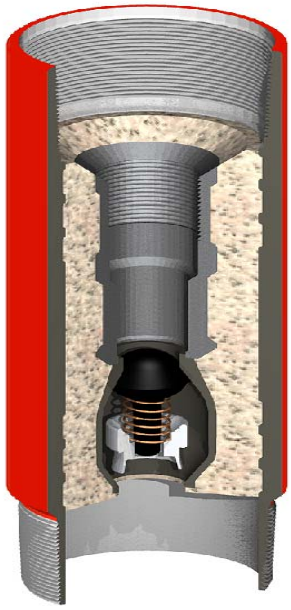
- **Float shoe and Float collar**
  - One-way valve that allows circulation while preventing backflow into the casing from annulus
- **Centralizers**
  - Maintain clearance between casing and borehole needed for a good cement job
- **Scratchers**
  - Remove filter cake from the borehole wall, to enable a better bond with the cement



Casing cementing equipment

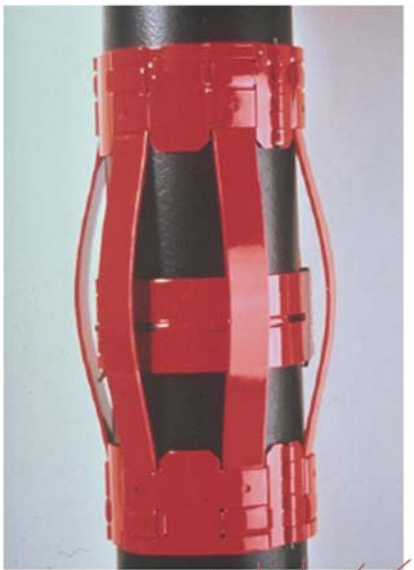


Float shoe



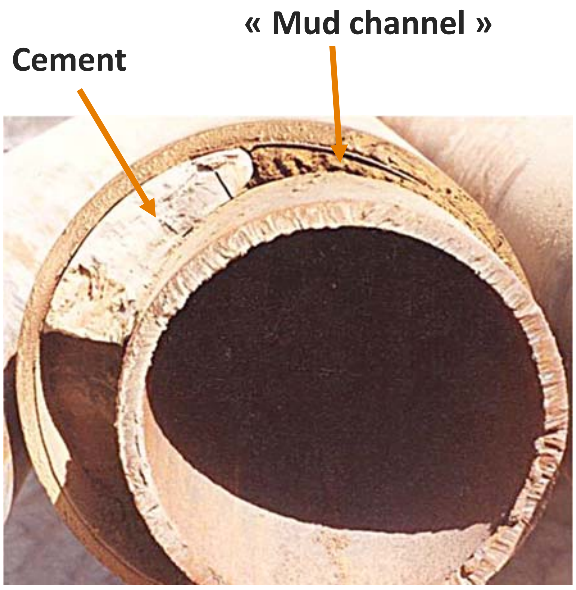
Float collar

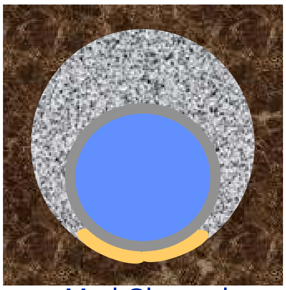
Centralizer



Scratcher

Casing centralizing

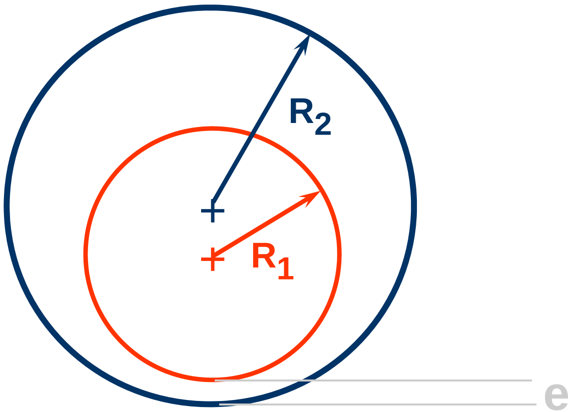




Mud Channel

Unsufficient casing centralizing has created partial displacement of the mud

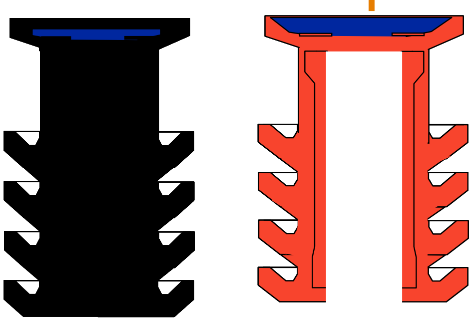
→ NO annulus seal



Stand Off = e x 100 / (R_2 - R_1)

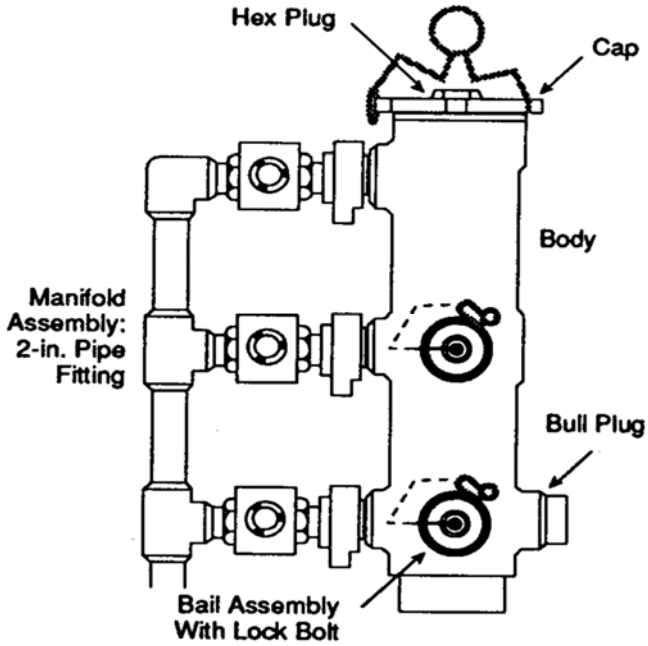
Recommended standoff: > 80%

Cementing head and plugs



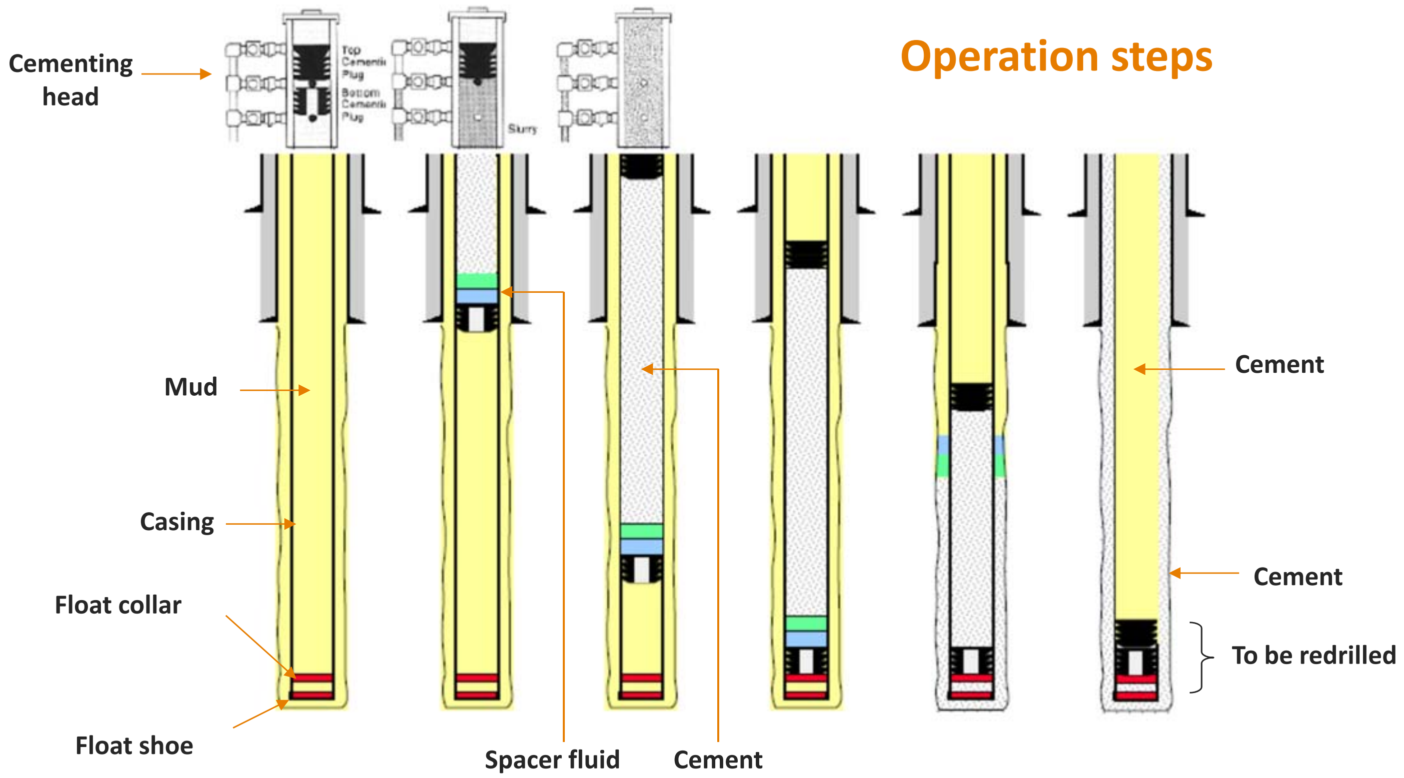
Tail plug

Head plug

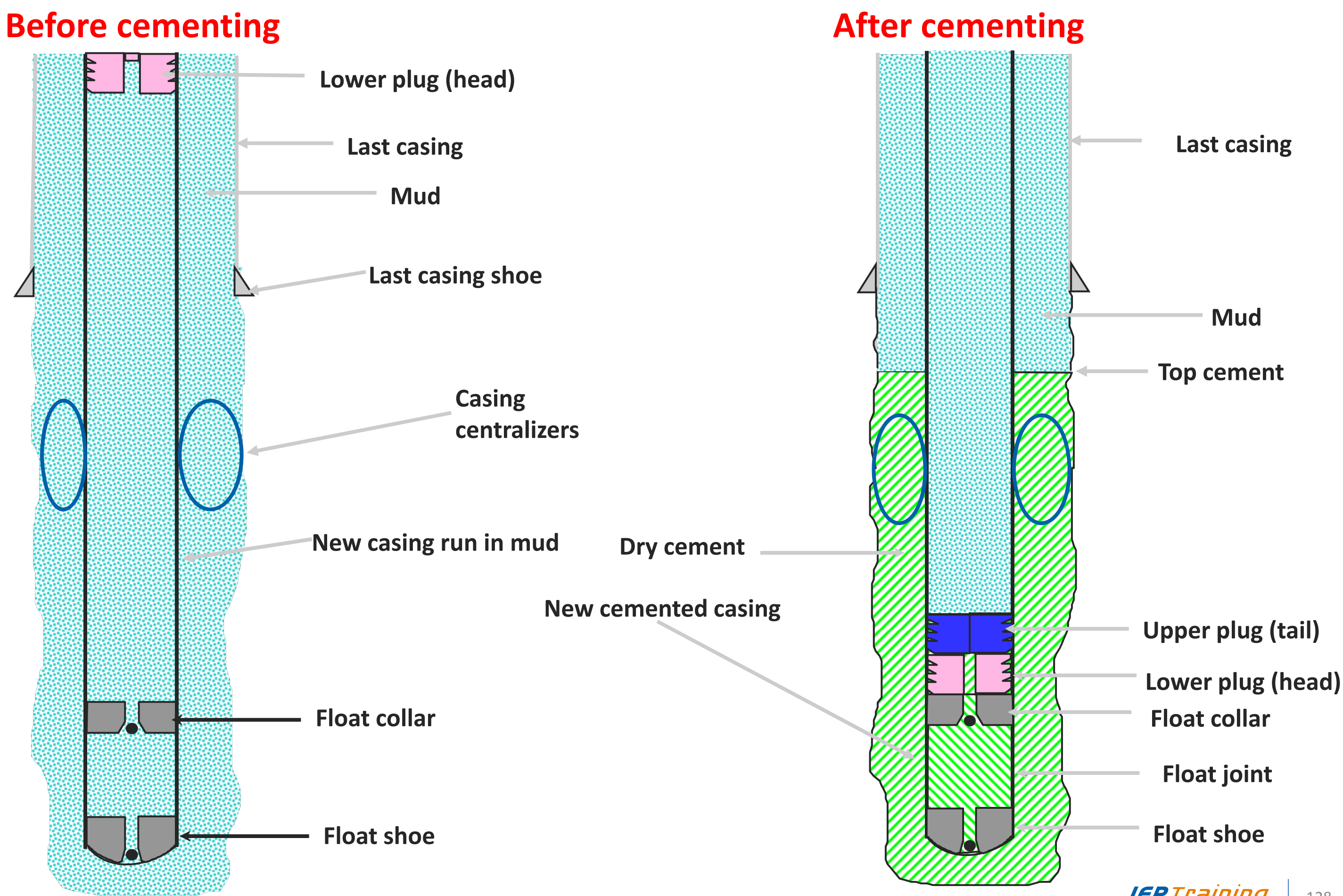


- **Purpose of cementing plugs**
  - To separate the cement from the mud
  - To scrap inside the casing wall
  - To provide a positive indication of the end of cement displacement

Casing cementing



Casing cementing



Key points to keep in mind

1. **Casing cementing purposes:**
   - Provide mechanical anchoring of casing string in formations
   - Isolate reservoirs/formations located behind casing.
   - Ensure annulus seal above reservoirs/formations.
   - Provides tightness of annulus base.
   - Prevent formation collapse and swelling (shale, salt, …)

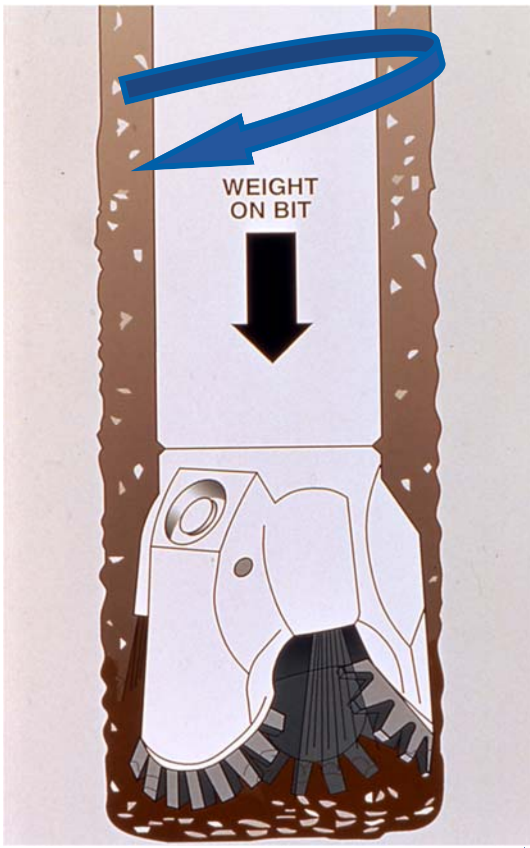
2. **Casing cementing equipment (from top to bottom)**
   - Cementing head (located on the rig floor)
   - Joints of casing equipped with:
     - Centralizers to prevent mud chaneling in annulus
     - Scratchers to remove mud cake and improve bond between cement and formation
   - Float collar
   - 2 or 3 joints of casing
   - Float shoe

Contents

Drilling bits

Drilling bit

- The bit is at the bottom of the drill string
- Cuts or crushes the rock, or both, usually as a result of a rotational motion and compression (weight on bit – WOB)
- Has to be changed when it becomes excessively dull or stops making progress

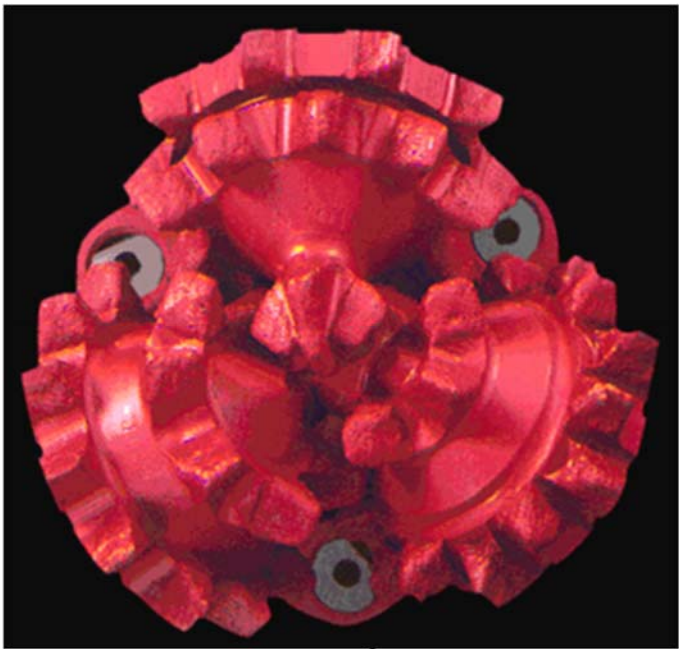


Drilling bits

Types of drilling bits

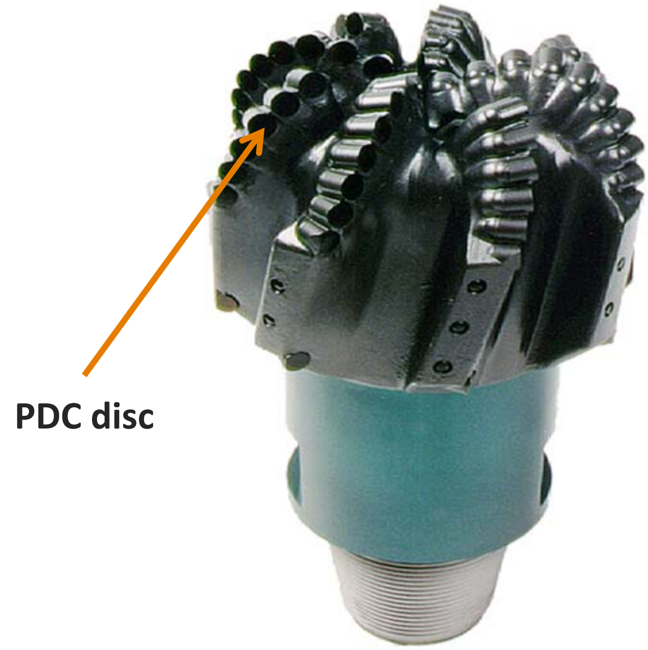
- Tricone bits (milled tooth or tungsten carbide inserts)
- Natural diamond bit
- Synthetic diamond bits (STRATAPAX, PDC, TSP)

Drilling bits



Bit nozzle

Drilling bits



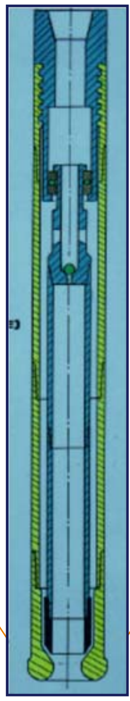
PDC bits (Polycrystalline Diamond Compact)

Typical operating parameters of drilling bits

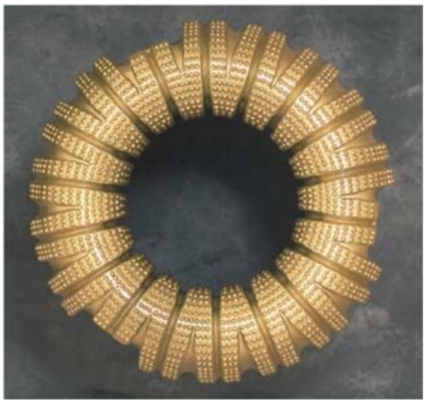
- **Bit drilling parameters**
  - Rotation: 50 up to 300 rpm
  - Weight on bit: 5 up to 30 tons
- **Rate of penetration (ROP): 1 m/hour up to 30 m/hour**
- **Bit life expectancy: several hours up to ~ 300 hours**

Coring tools

Core head
w/tungsten carbide cutters

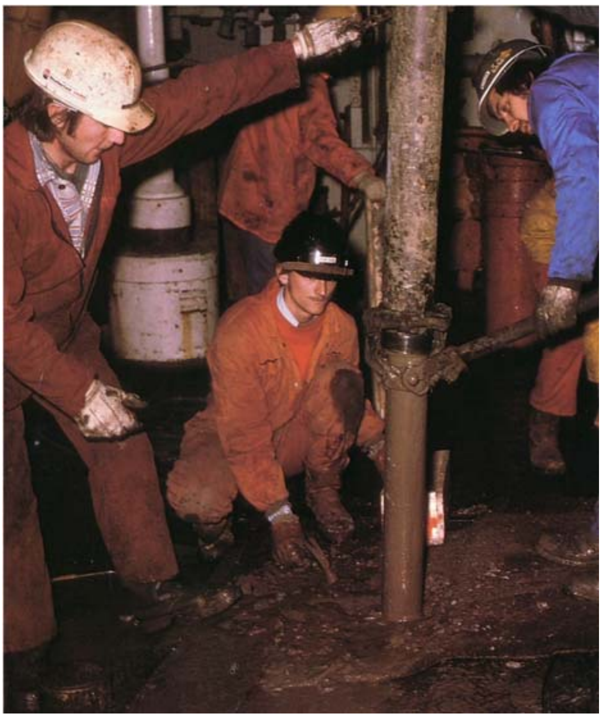


Core barrel



Diamond core cutters

Coring



Recovering the core

Low perm rock

Reservoir rock

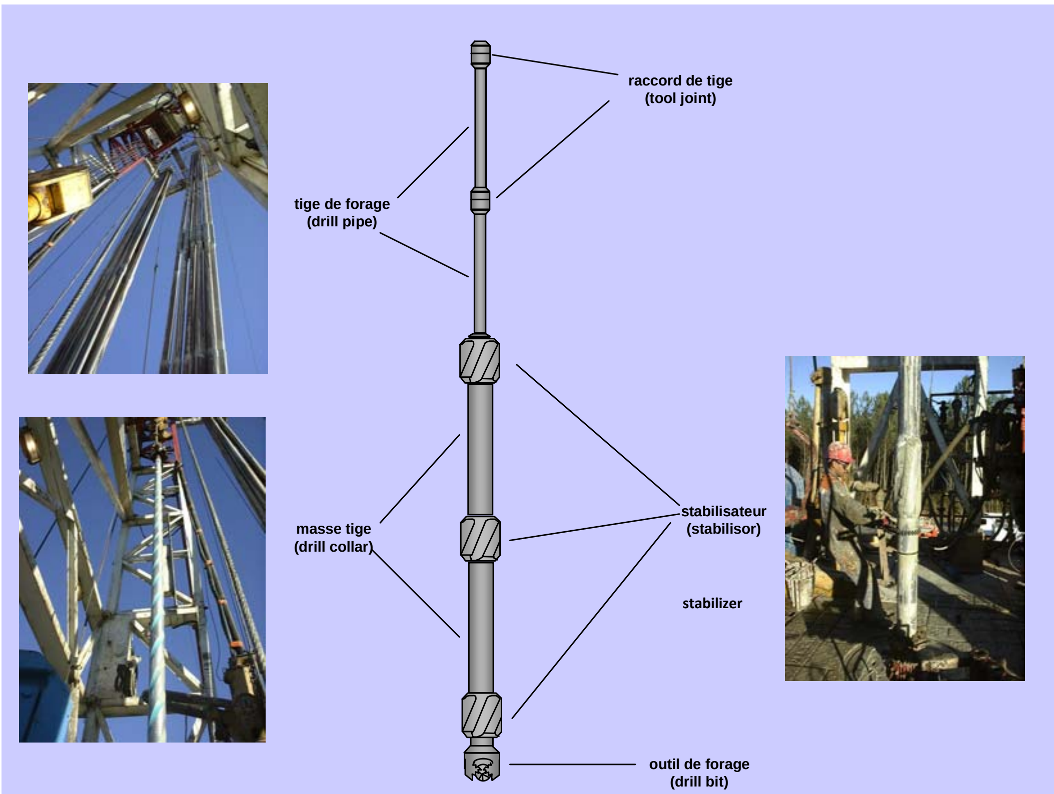
Oil

Key points to keep in mind

1. **Main types of drilling bit**
   - Tricone bit: milled tooth or tungsten carbide inserts
   - Monobloc type bits:
     - PDC bits (Polycrystalline diamond compact cutters)
     - Diamond bits
   - Core heads (diamond or PDC core head)
   - All bits have nozzles for mud circulation
2. **Drilling parameters**
   - Weight on bit (WOB)
   - Rotational speed (number of revolutions per minute: RPM)
   - Hydraulic: mud flowrate, jetting
   - Drilling parameters depends mainly on the hole diameter being drilled. The bigger the hole, the greater the WOB, RPM and mud flowrate
3. **Bit performance**
   - Bit performance is characterized by two parameters that have to be combined to calculate the global economic performance of a bit taking the cost of the bit and the daily rate of the drilling rig into account :
     - Rate of penetration (ROP) in meters/hour
     - Bit life in hours

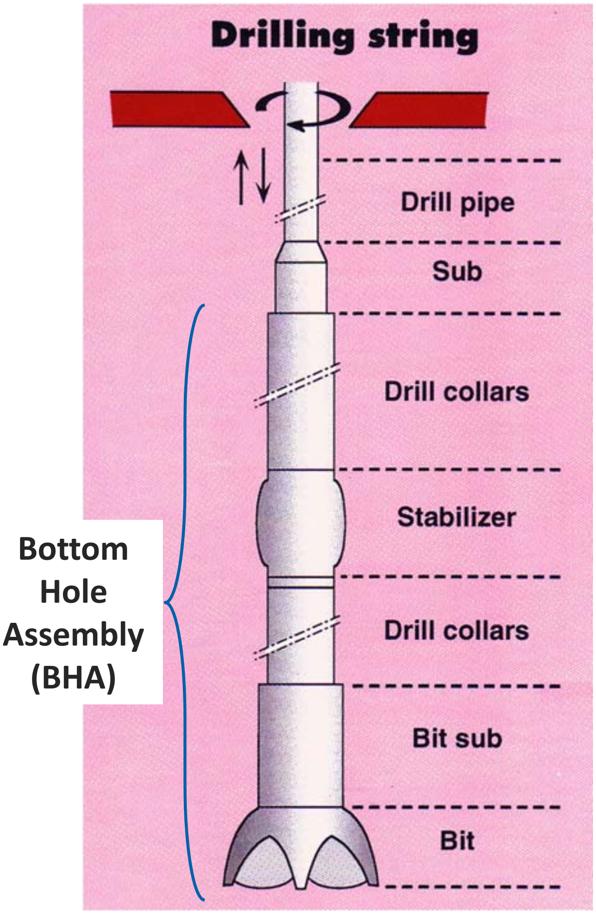
Contents

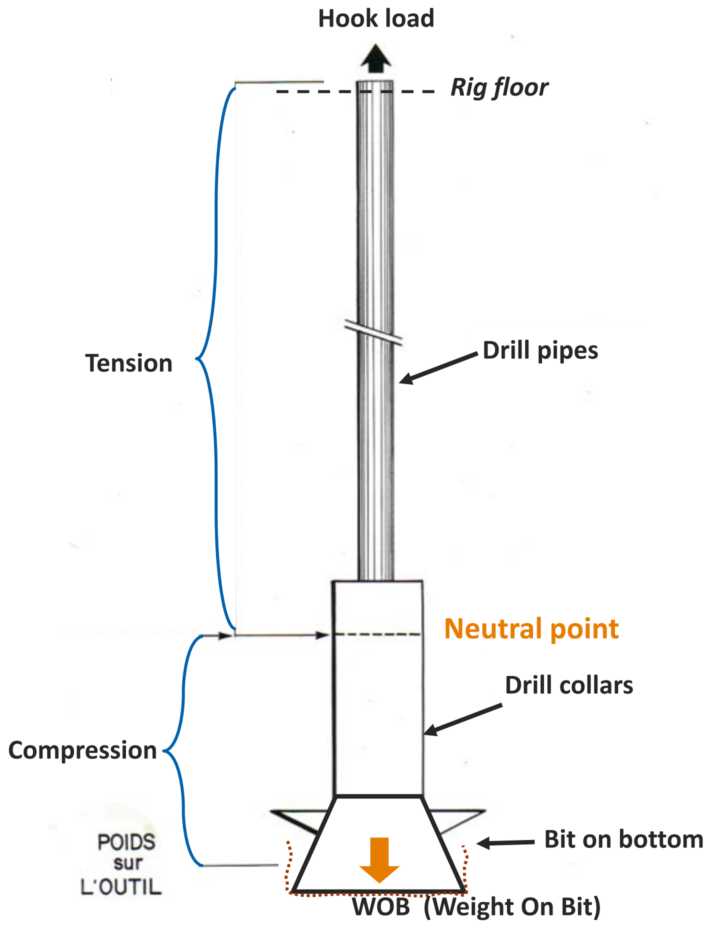
Drill string main components



Drill Collars are used to apply weight on the bit.
The neutral point is at ~ 85 % of total DC weight.

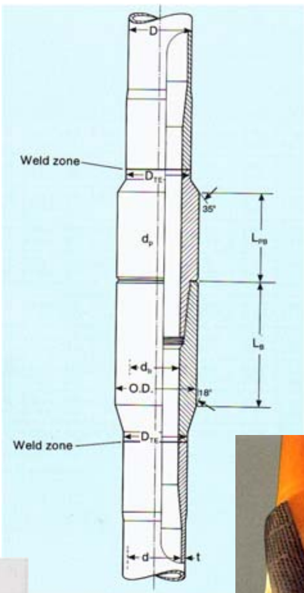
Drill string



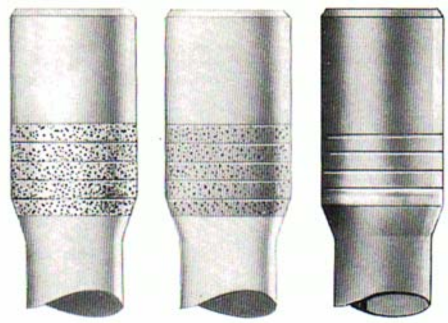


Drill string components

Drill pipes (DP)



Drill pipe tool joint



Drill collars (DC)

Stabilizers

Drill string handling

☞ ***Film:loss of concentration***

Key points to keep in mind

- **Main components of the drillstring (from top to bottom)**
  - Kelly or top drive
  - Drill pipes
  - Heavy weight drill pipes with drilling jar
  - Bottom Hole Assembly (BHA) consisting of:
    - Drill collars
    - Stabilizers
    - Drilling bit

- **The drill string**
  - Transmits the loads for the drilling bit to drill: compression (WOB) and rotation
  - Provides a conduit to inject the mud down to the bit. The mud returns back to the surface in the annulus space between the drill string and the open hole and the casing.

Contents

Potential problems in drilling

Main sources of problem

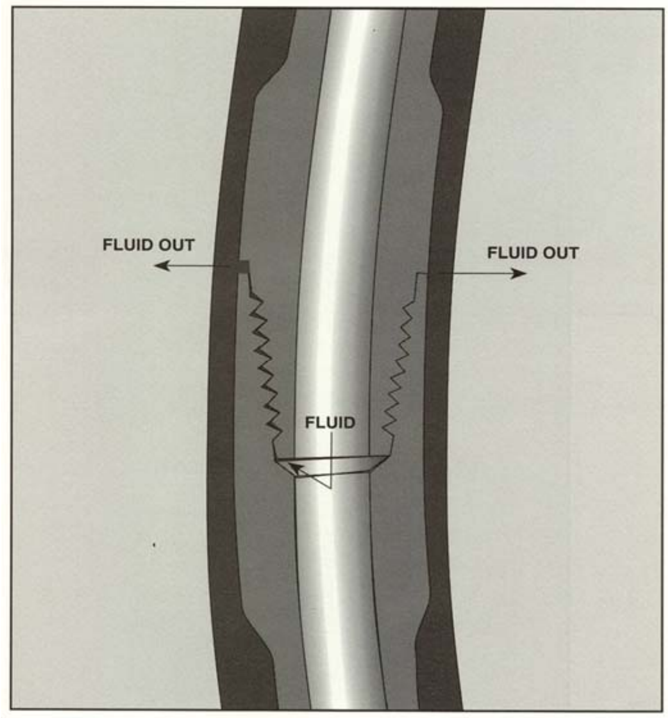
- **Downhole equipment failure**
  - Drill pipe, drill collar or thread failure
  - Tricone bit failure

- **Formation unstability**
  - Difficult drilling conditions resulting from tight hole or instable borehole
  - Pipe stuck resulting from instable borehole
  - Pipe stuck by "differential sticking"

- **Loss of hydrostatic balance**
  - Drilling fluid losses to formation
  - Influx of formation fluid (kick)
  - Internal or external blow out

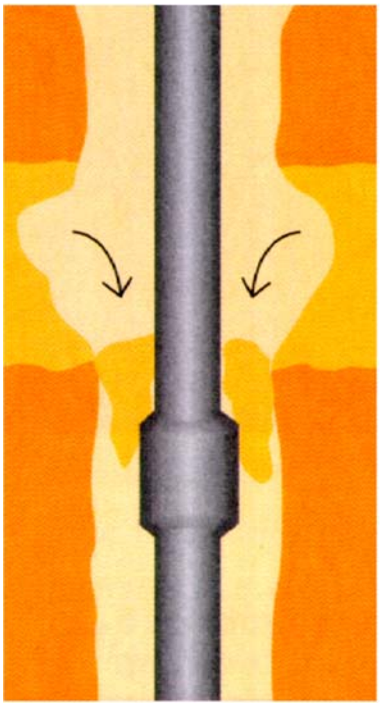
Downhole equipment failure

Swelled thread box (make-up torque)

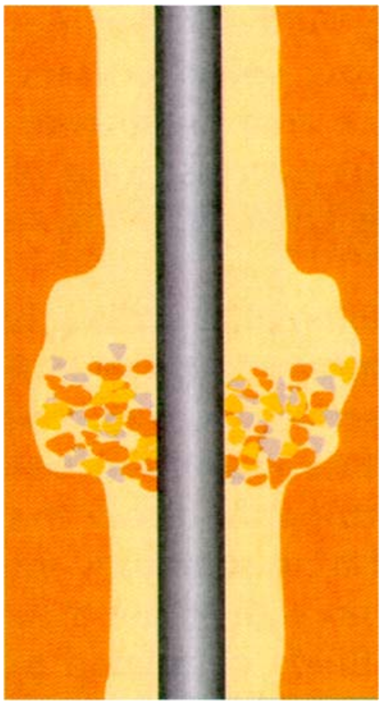


Washout indication: slow DP pressure drop

Formation unstability



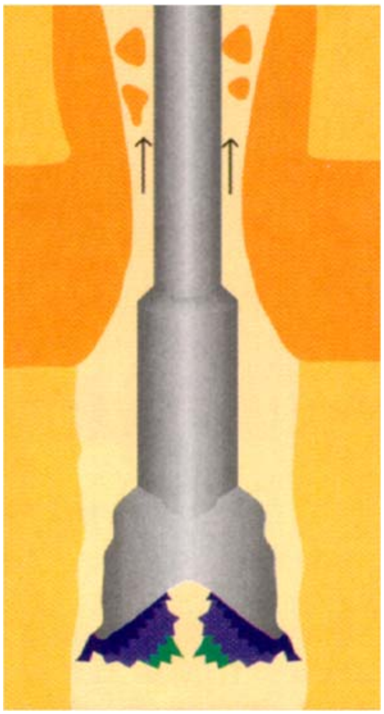
Fractured or faulted formation

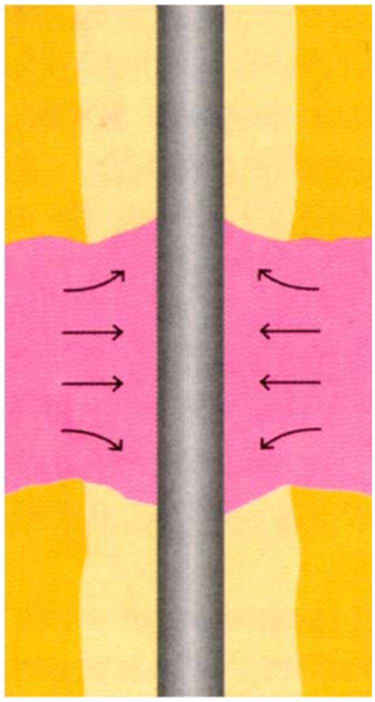


Formation cavings

Formation instability

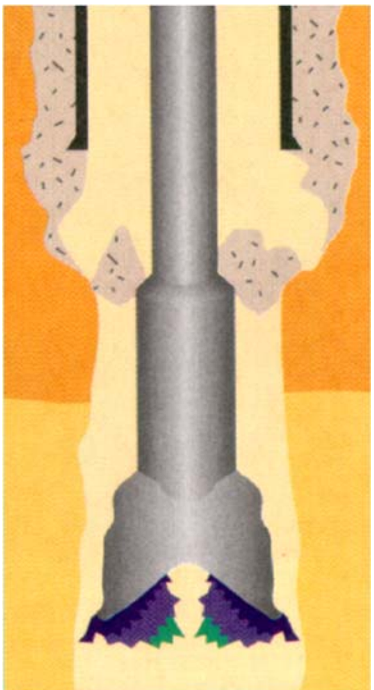
Tight hole



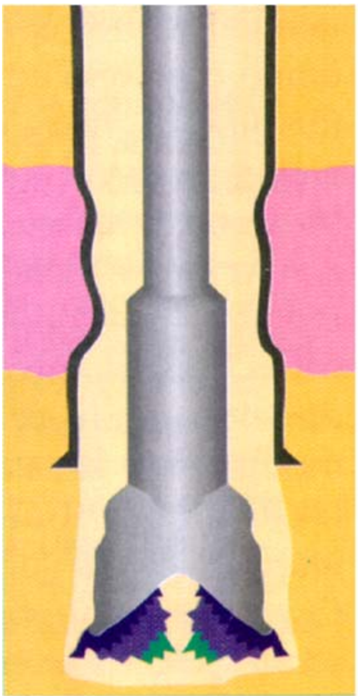


Formation swelling or flowing

Potential problems in drilling



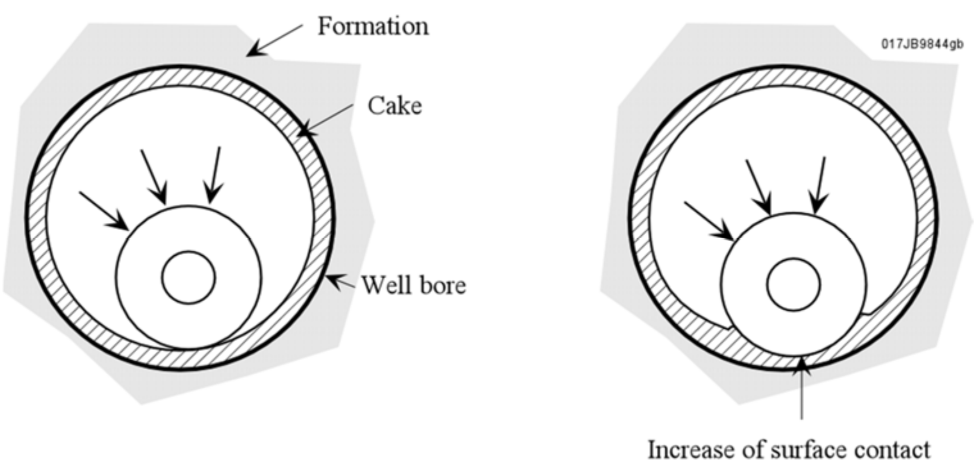
Cement blocks falling



Casing collapse

Dropped objects

Differential sticking



- **60 to 80 % of occurrences are due to:**
  - A too high difference between the pore pressure and the mud hydrostatic pressure (too high mud weight)
  - Presence of a porous and permeable formation.
  - Presence of a thick and porous mud cake on the formation walls
  - Bottom Hole Assembly in contact with the formation

Potential problems in drilling

Main sources of problem	Typical remedial action
Downhole equipment failure	
• DP, DC or thread failure	⇨ **Fishing**
• Tricone bit failure	⇨ ”
Formation unstability	
• Difficult drilling conditions	⇨ Hole **reaming, redrilling**
• Pipe stuck resulting from unstable borehole • Pipe stuck by “differential sticking”	⇨ Attempt **fishing**, milling, washover, etc. … if unsuccessful **side-track**
Loss of hydrostatic balance	
• Drilling fluid losses	⇨ **Cure losses** W/ LCM or cement
• Influx of formation fluid (kick)	⇨ **Circ out kick**, control well
• Internal or external blow out	⇨ Attempt to **kill well**

Potential problems in drilling: remedial actions

Typical remedial action plan in case of stuck drill string

1. Locate the free point
   - Using Free Point Indicator electric tool

2. Back off or cut the drill string above the free point

3. Fishing
   - Attempt to fish stuck pipes by jarring
   - If not successful, then milling or washover are possible options

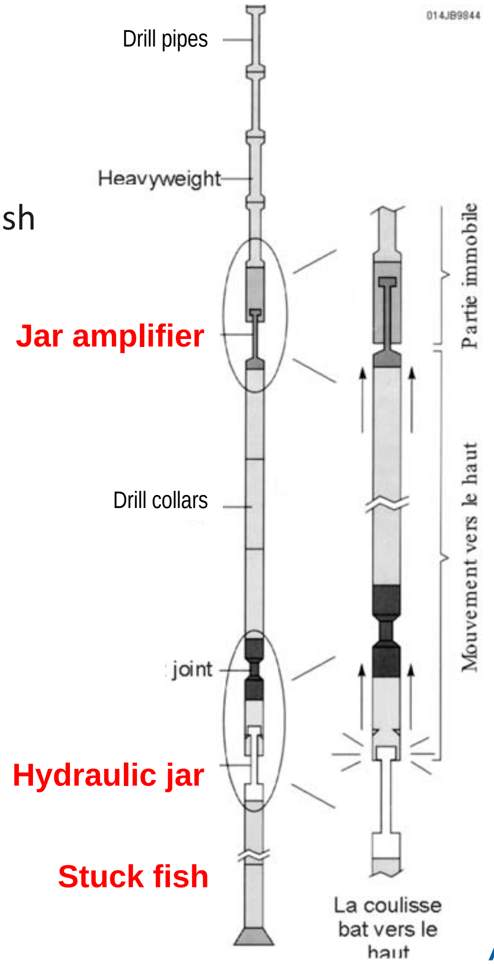
4. Side-tracking if fishing unsuccessful

Note: *Side-tracking is often preferred to fishing operations (difficult, time consuming, not allways successful)*

… but try to avoid extreme situations !

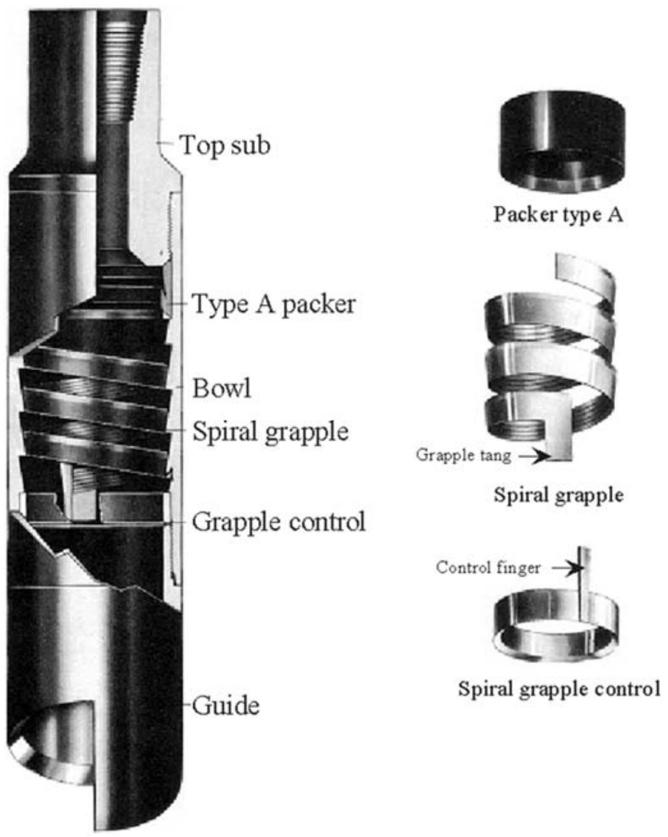
Potential problems in drilling: remedial actions

- **FISHING STRING**
  - Includes hydraulic jar and jar amplifier to deliver repetitive blows (shocks) on a stuck fish

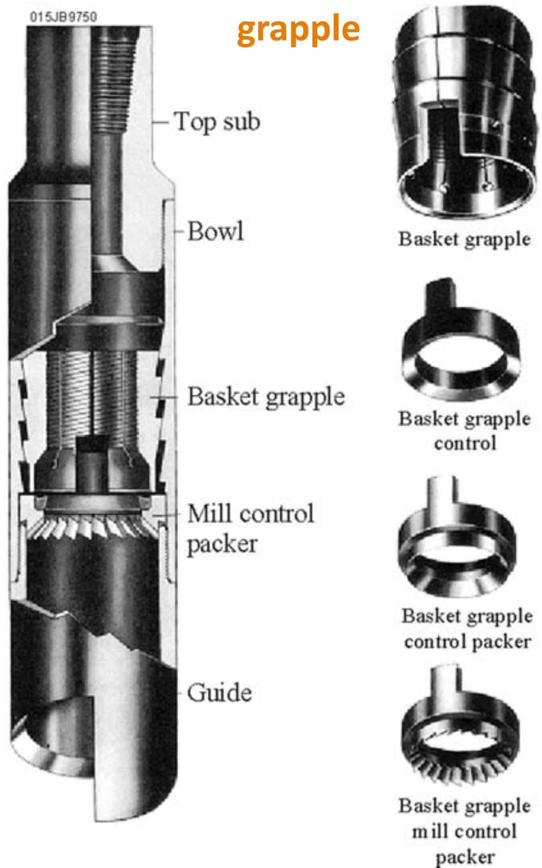


Fishing tools

Overshot with spiral grapple

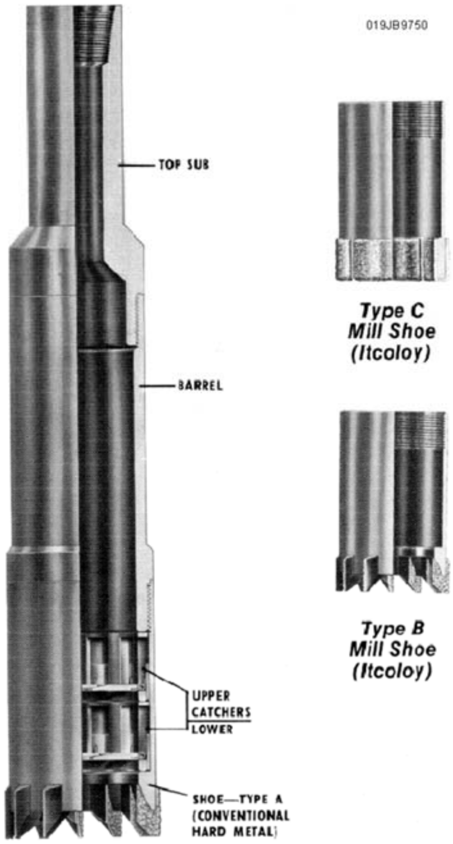


Overshot with basket grapple

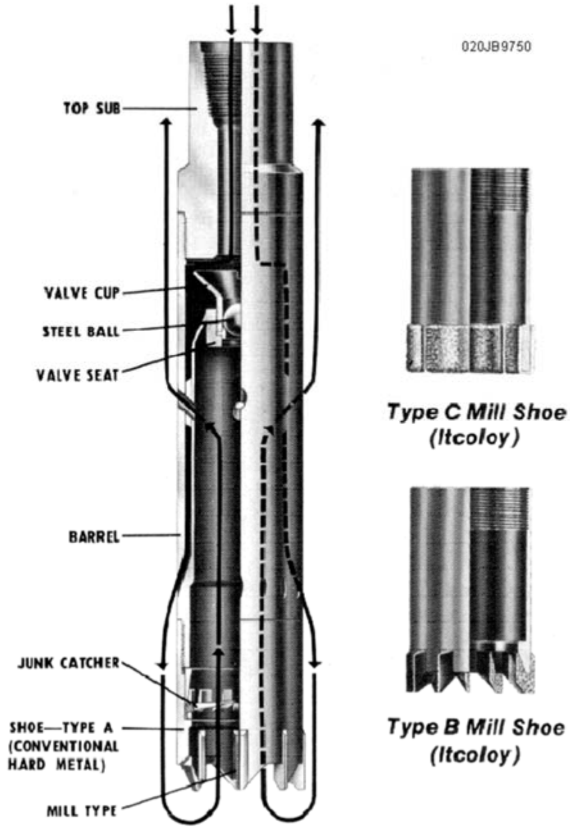


Some fishing tools …

Washover pipe



Junk basket



Key points to keep in mind

1. Main causes of drilling problems:

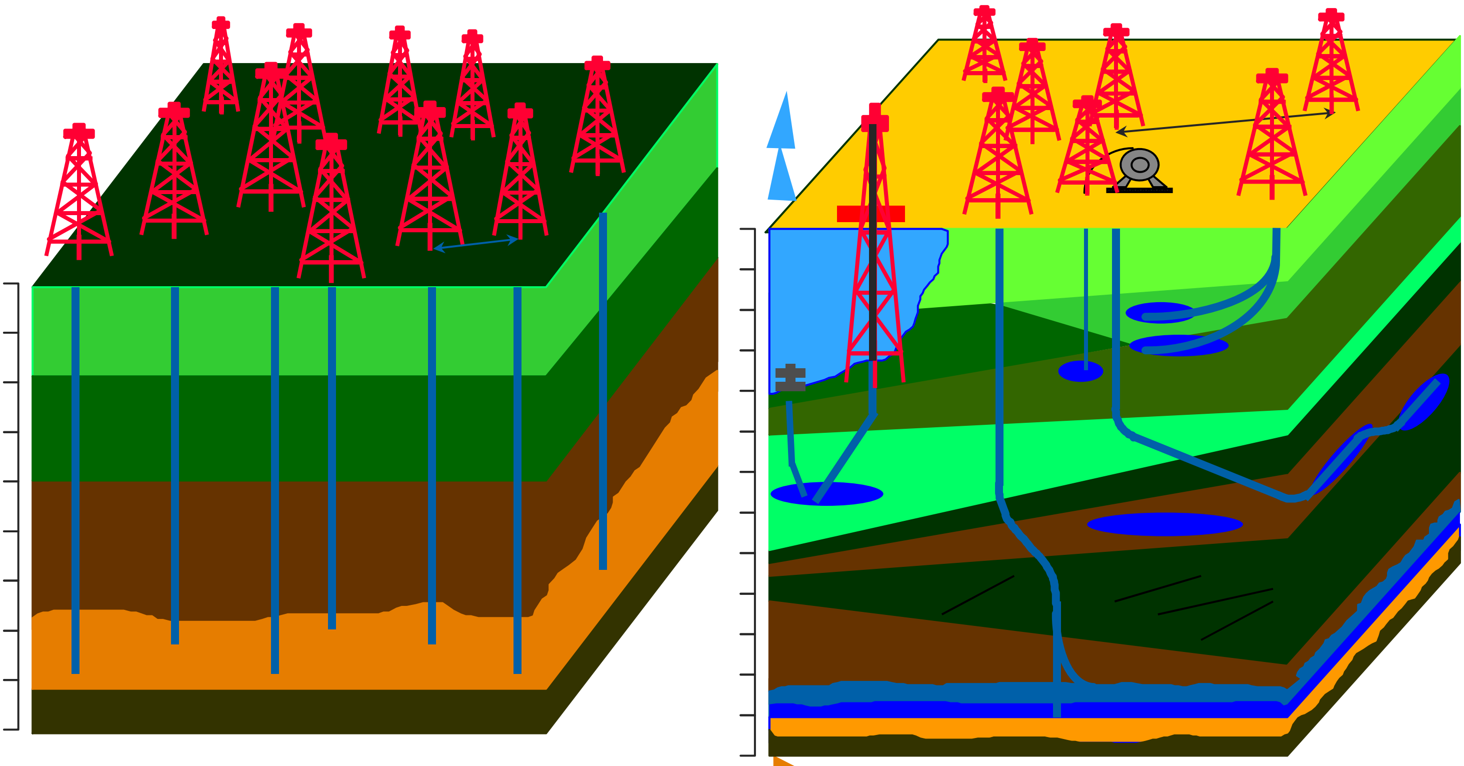
- Downhole equipment failure
- Formation mechanical unstability
- Loss of hydrostatic balance

2. Typical stuck pipe remedial program:

- Locate the free point
- Back off or cut the drill string above the free point
- Attempt to catch and free the fish
- If not successful → Side track well above the fish left in hole

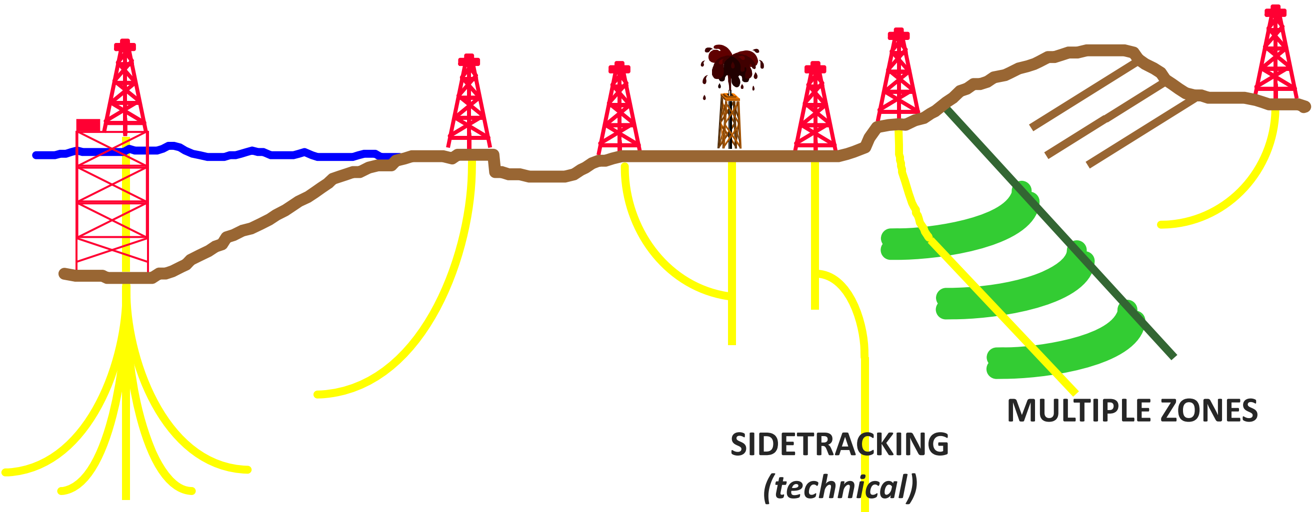
Directional Drilling

Contents



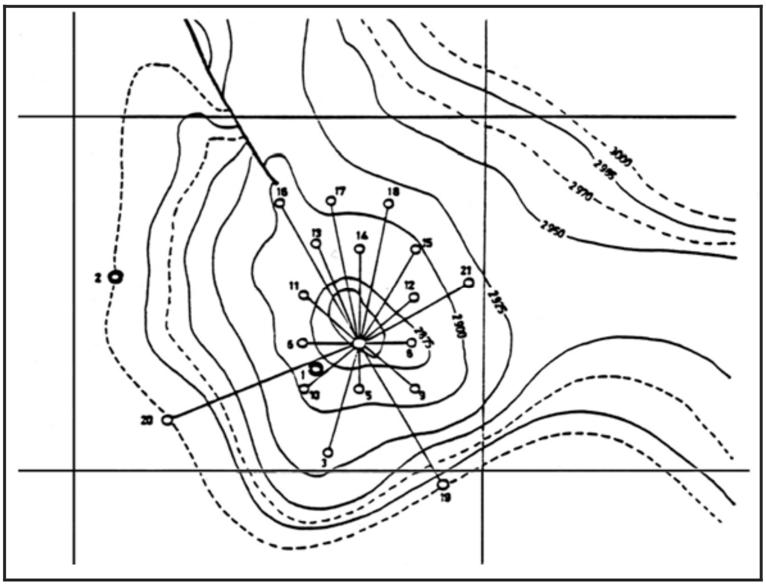
Evolution of architecture over the last 30 years

Main applications



Main applications

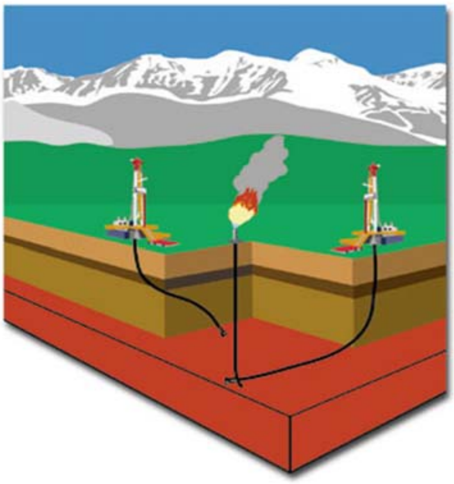
Multi-wells platforms (clusters)



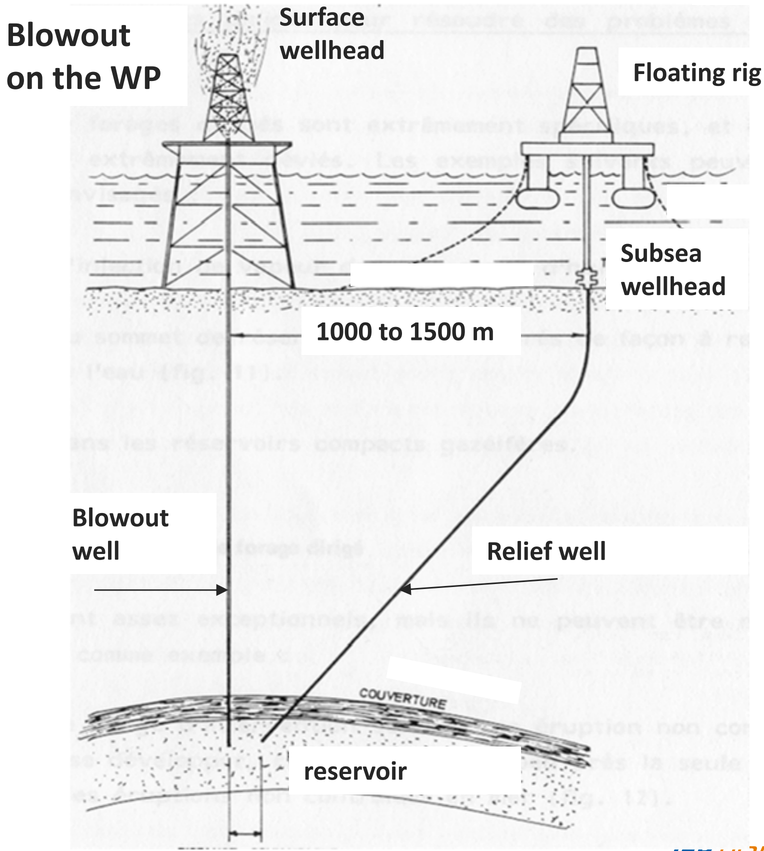
Drilling onshore on clusters

Main applications

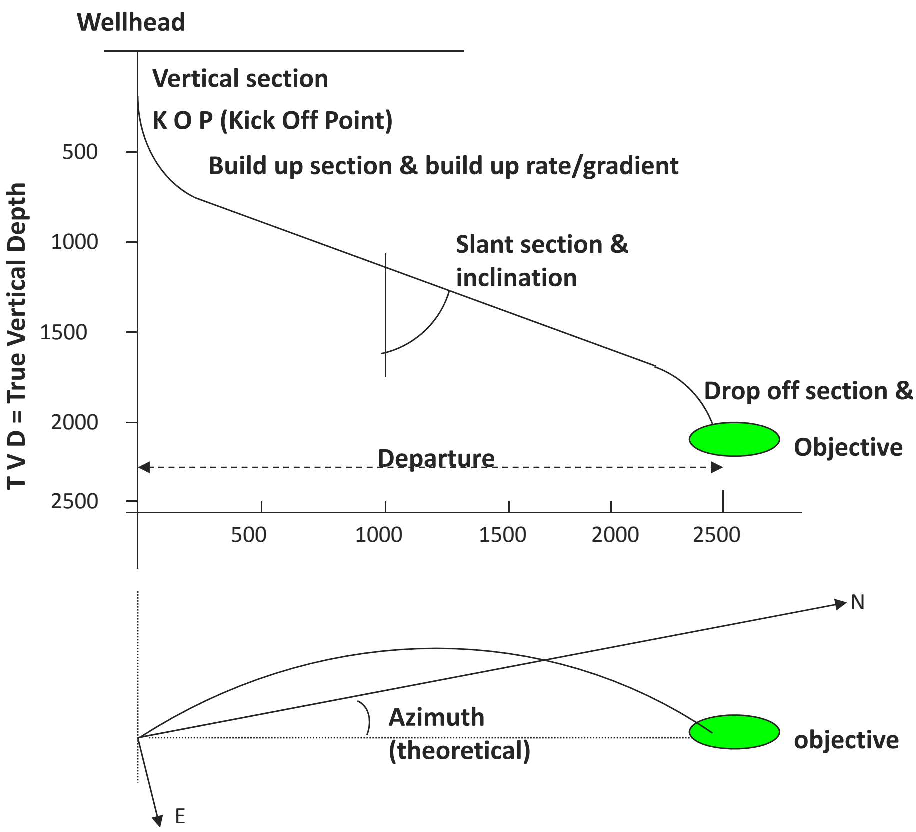
Relief wells drilled directionally



Source / illustration: Books from IFP and
"Chambre Syndicale de la Recherche et de la Production du Pétrole et du gaz naturel"



Directional drilling: terminology



Projection on vertical plan

T M D = True Metrage Depth

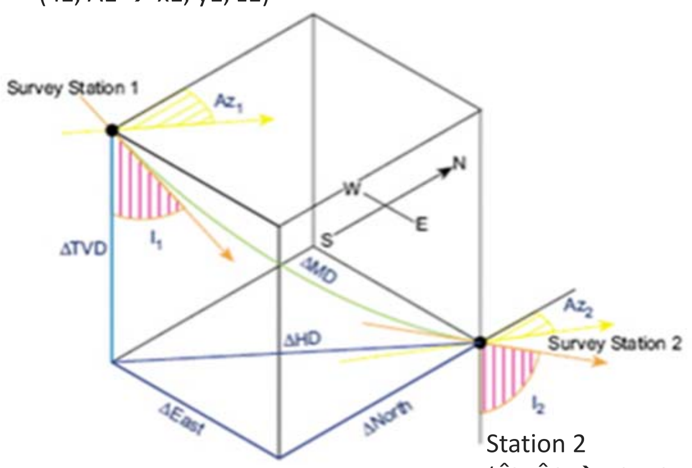
= length of the well

Projection on horizontal plan

Surveys performed on well trajectories

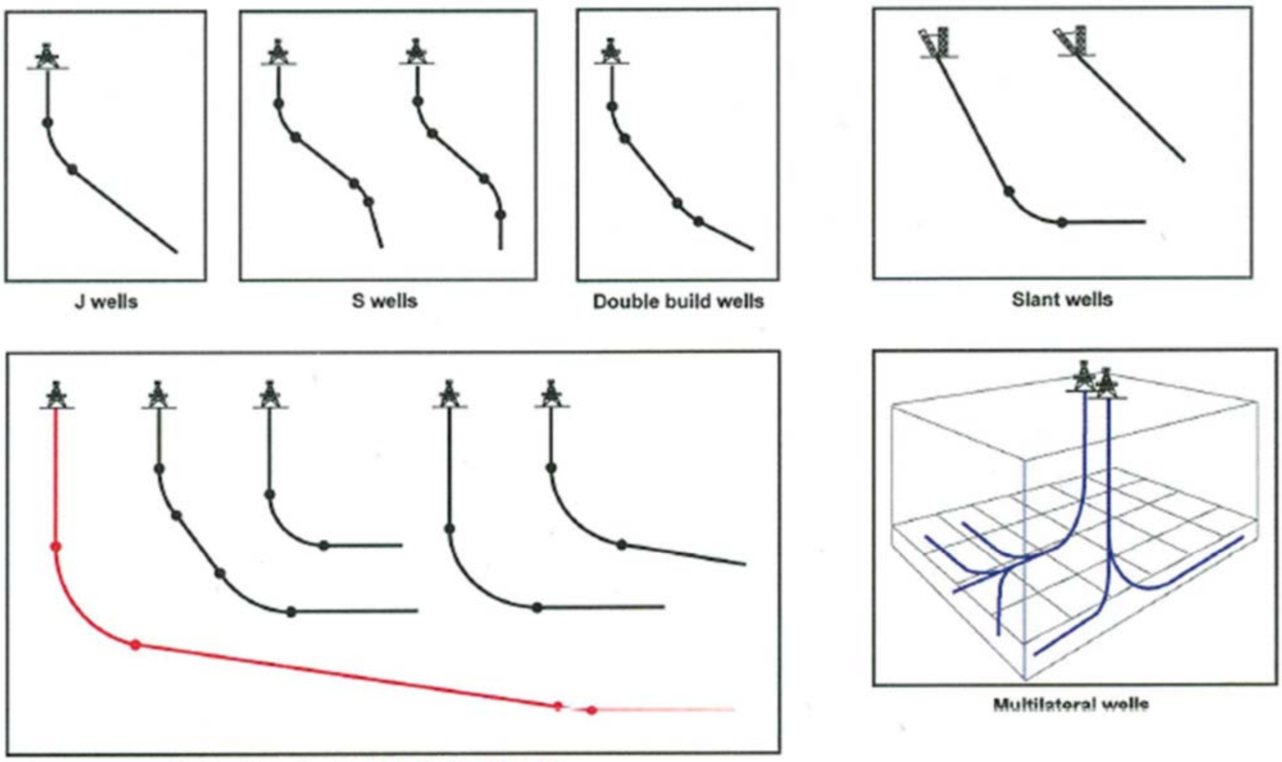
- **Tools for downhole measurements:**
  - Singleshots & multishots
  - Steering tools
  - MWD Measurement While Drilling, (deviation surveys)
  - LWD Logging While Drilling
  - Gyroscopic surveys
- **Measured parameters**
  - Drilled length
  - Well inclination
  - Well azimuth
- **Calculation (several methods)**
  - X departure East-West
  - Y departure North-South
  - Z Vertical depth (TVD)

Station 1
(Î1, Â1 → x1, y1, z1)



Station 2
(Î2, Â2 → x2, y2, z2,)

Directional drilling: well profiles



J wells

S wells

Double build wells

Slant wells

Horizontal wells & Extended reach well

Multilateral wells

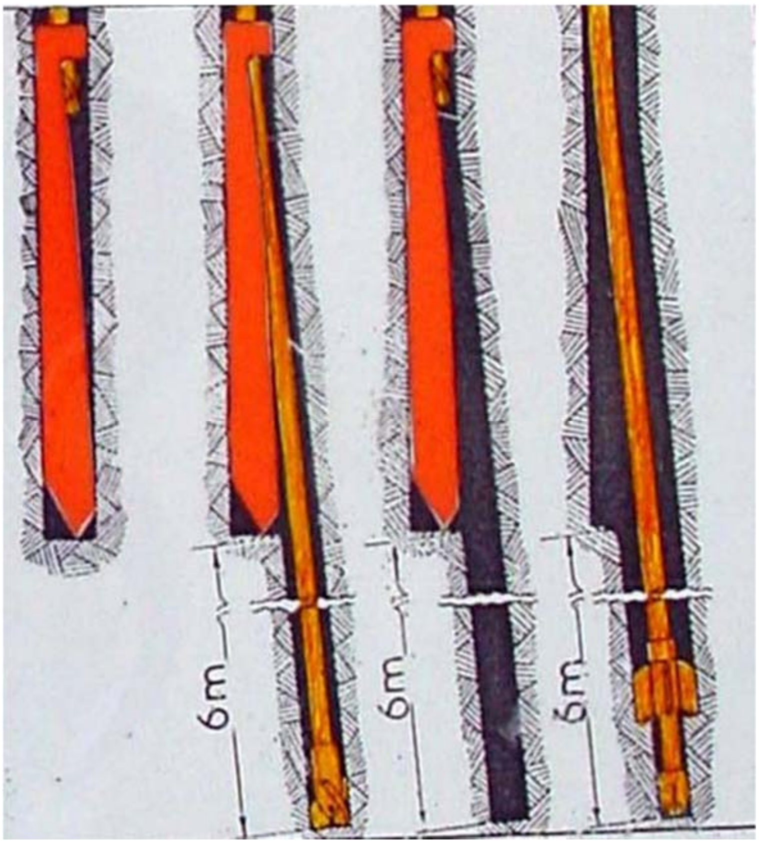
Contents

Methods for directional well construction

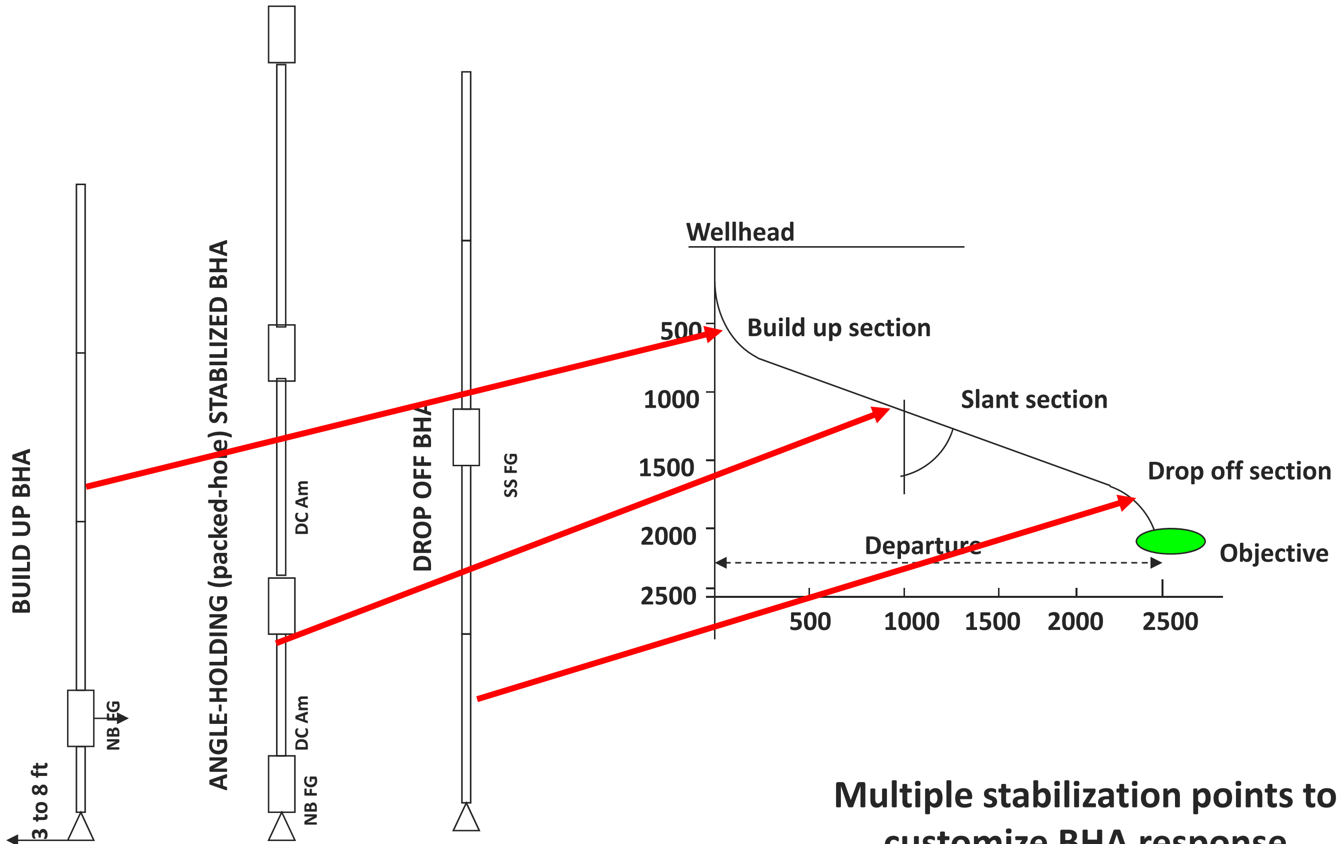
- **With “whipstock”**
- **With rotary drilling**
  - Stabilized BHA
- **With steerable tools**
  - With downhole PDM motor + bent sub
- **With Rotary Steerable Systems (RSS)**

Whipstock

Nowadays this tool is used for very specific applications (exit from tubing…)



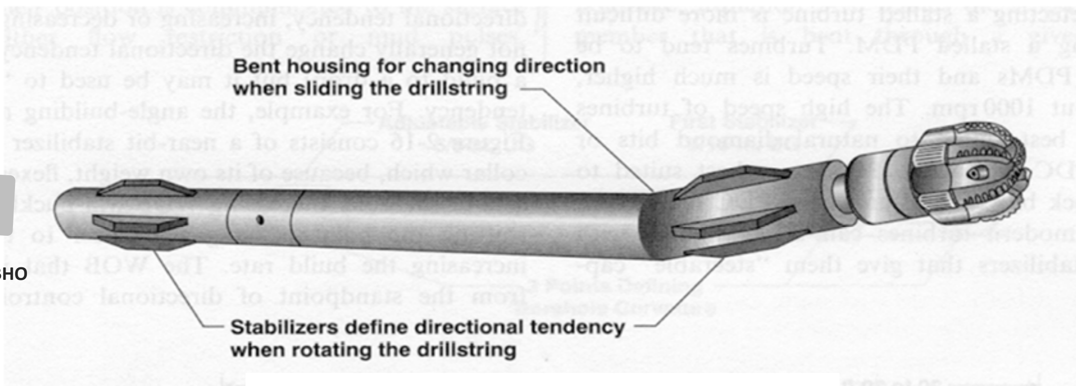
Rotary drilling with stabilized BHA



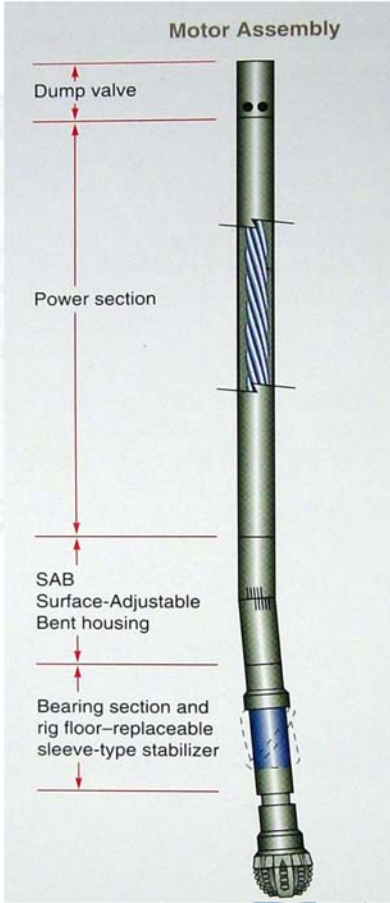
Source / illustration: Books from IFP and "Chambre Syndicale de la Recherche et de la Production du Pétrole et du gaz naturel"

Multiple stabilization points to customize BHA response

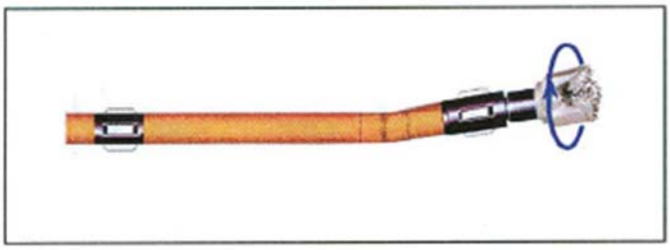
PDM motors and bent subs
(steerable motor configuration)



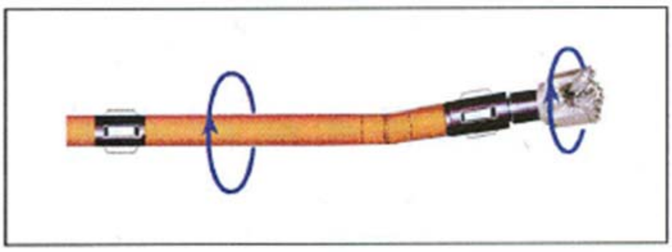
UBHO = (Universal Bottom Hole Orienting Sub); it is a seat for a measuring tool to take measurement of the tool face



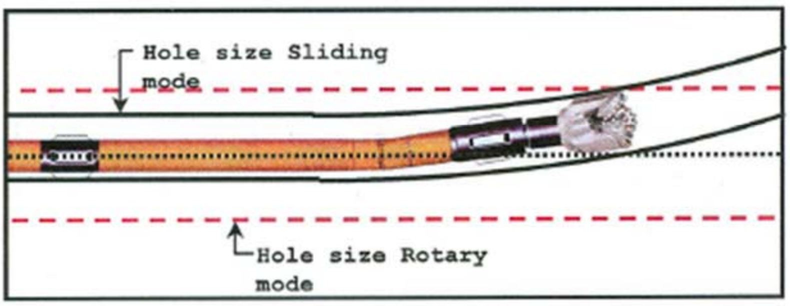
PDM motors and bent subs: rotary and/or sliding mode



Sliding mode

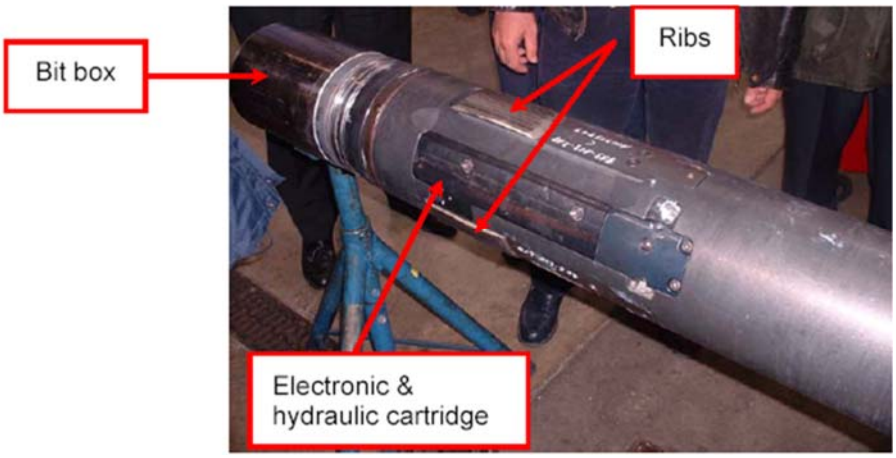


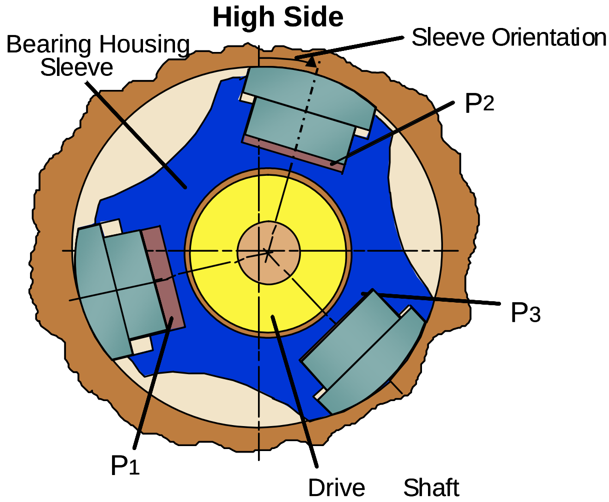
Rotary mode



Hole size versus Drilling mode

Rotary steerable system



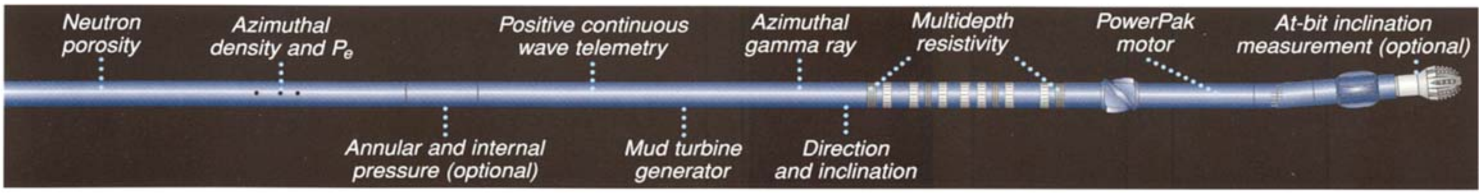


Directional drilling: measuring deviation

- **The well path is monitored at intervals, even during straight-hole drilling: drilled depth, inclination, magnetic azimuth are measured and recorded**
- **The survey tools used include:**
  - Magnetic single shot surveys (most common for straight wellbores)
  - Magnetic multi-shot surveys
  - Gyroscopic surveys
  - Steering tools
  - **Measurement while drilling (MWD) surveys (most common for directional wellbores)**

Different measurements with MWD and/or LWD

- **Deviation parameters**
  - Inclination
  - Azimuth
  - Tool face
  - Temperature
- **Formation evaluation parameters**
  - Gamma ray
  - Resistivity
  - Density
  - Neutron (porosity)
  - Sonic
- **Drilling parameters**
  - Torque
  - WOB
  - Vibrations
  - Annular pressure



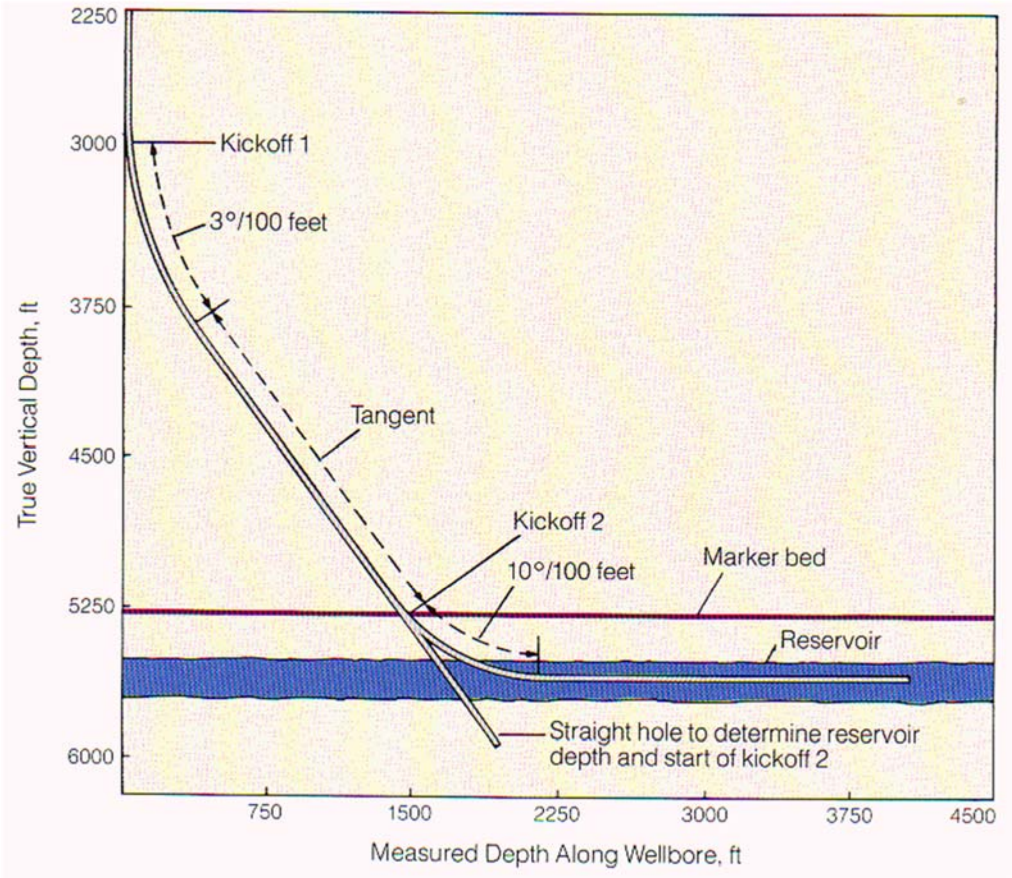
Contents

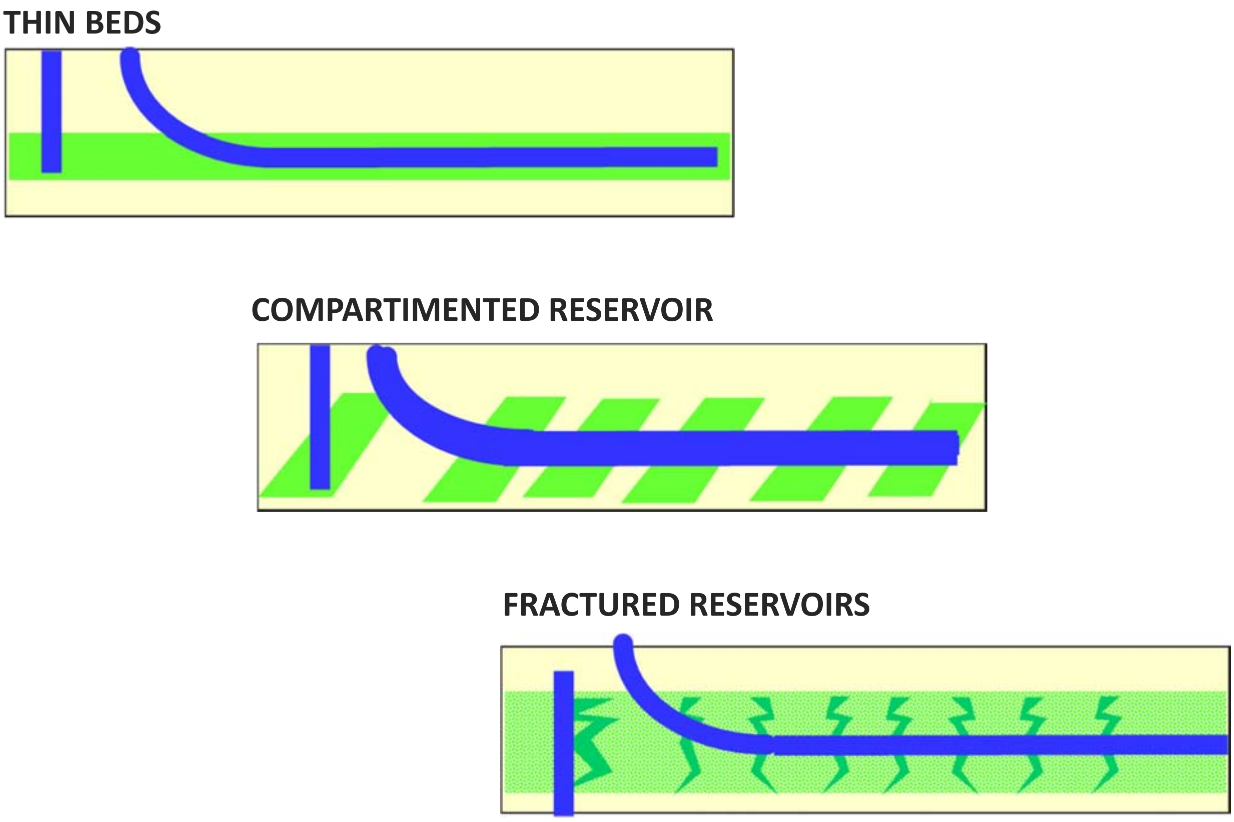
Horizontal wells: some advantages

- Increased well productivity
- Improved reservoir drainage
- Increase of reserves

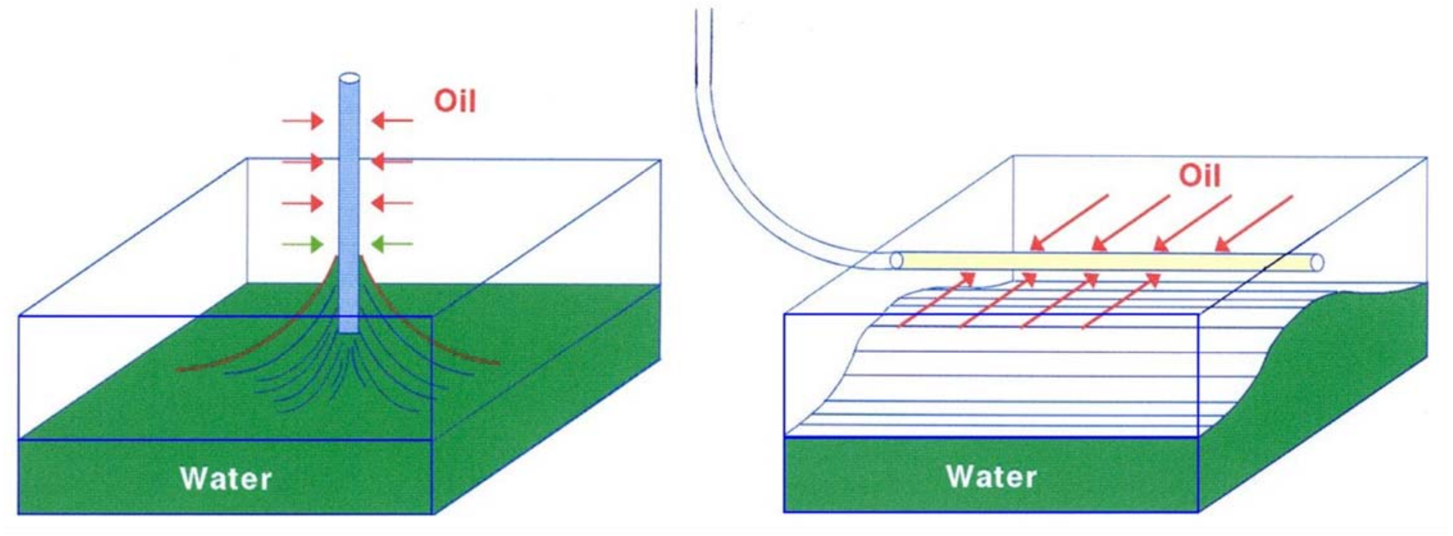
- Reduction of number of wells drilled
- Reduction of technical cost per barrel

Horizontal well – Construction / profile

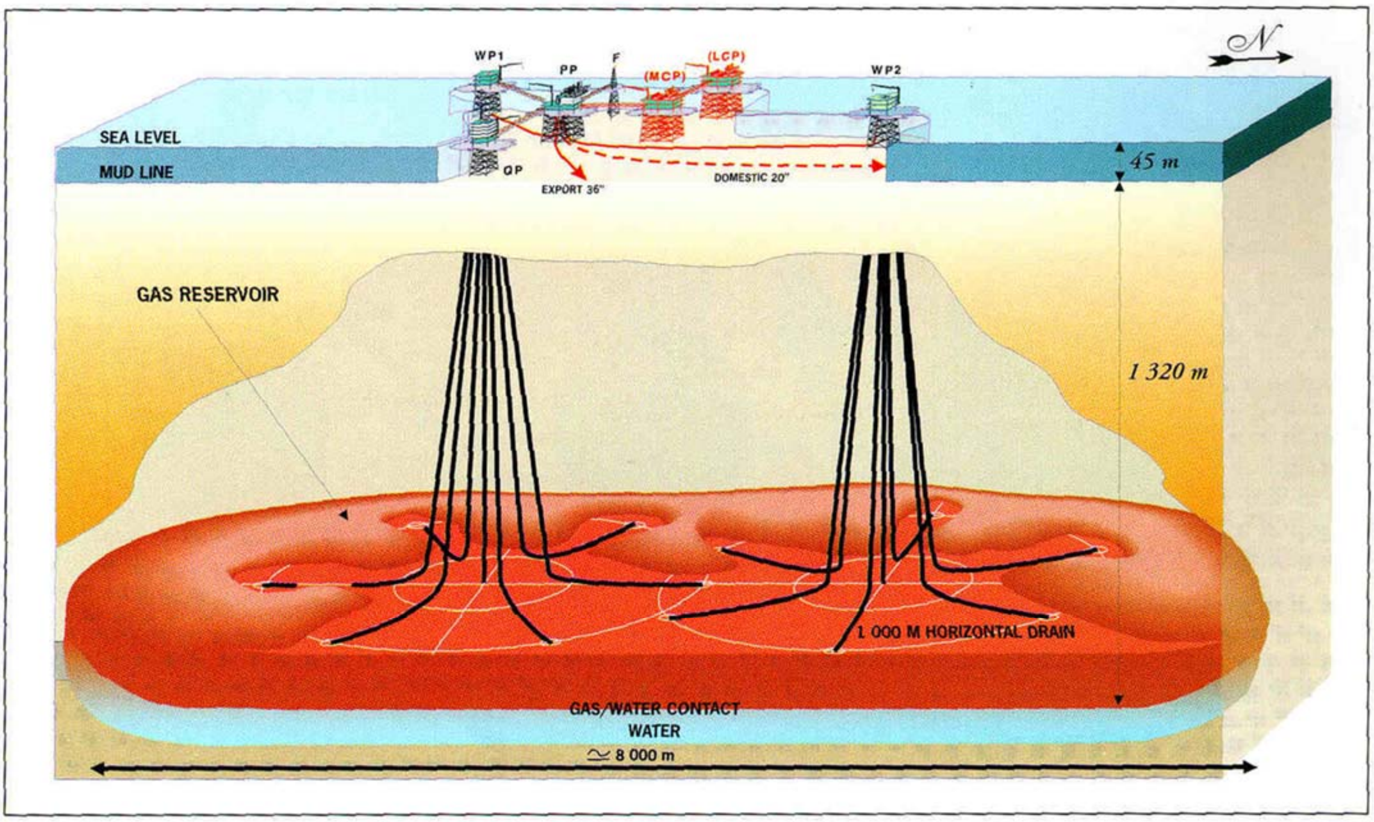




Water coning

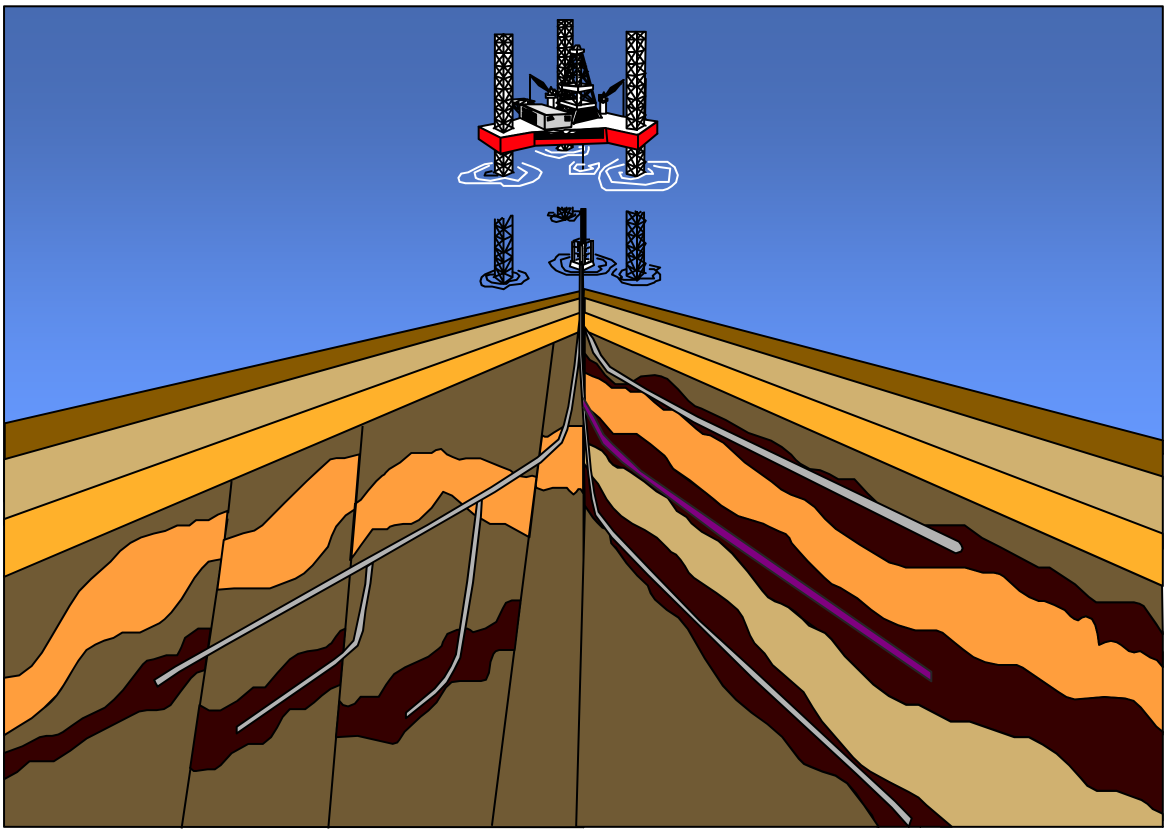


Directional drilling – Horizontal drilling from platforms

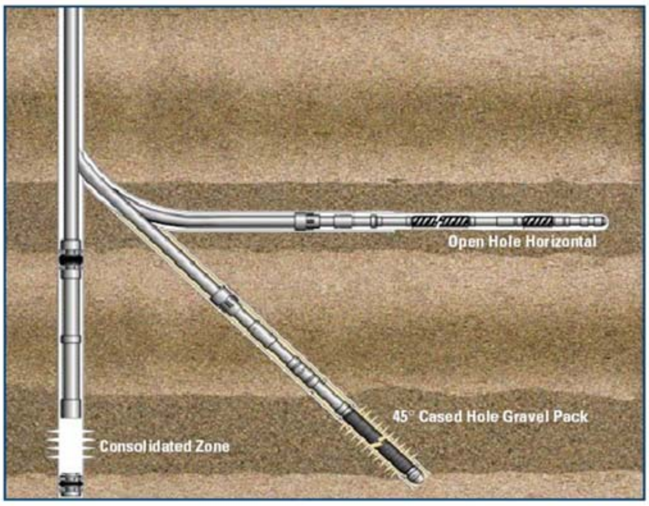


Contents

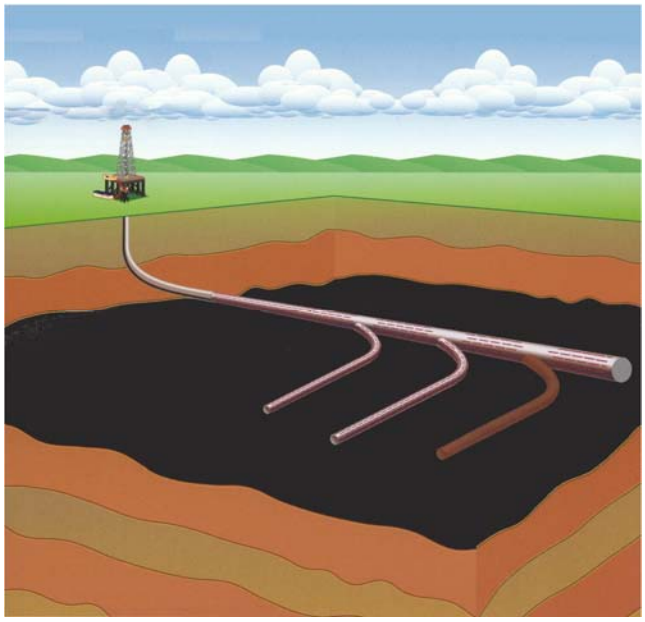
Applications of multilateral drilling



Applications of multilateral drilling



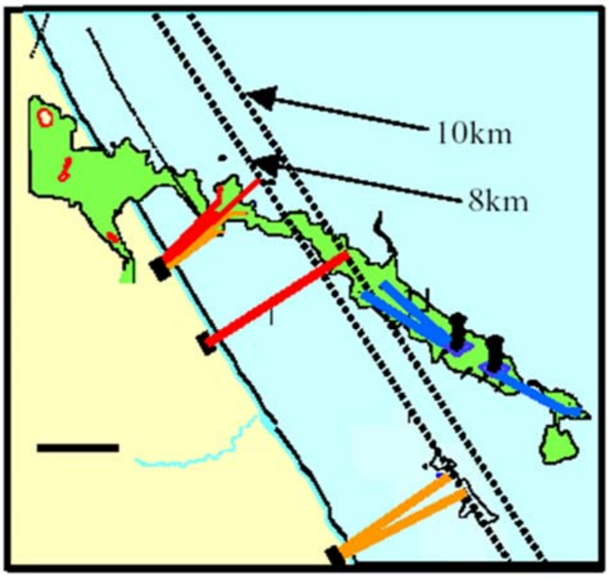
Re-entry wells



Multi-drains well

Contents

« ERD wells »

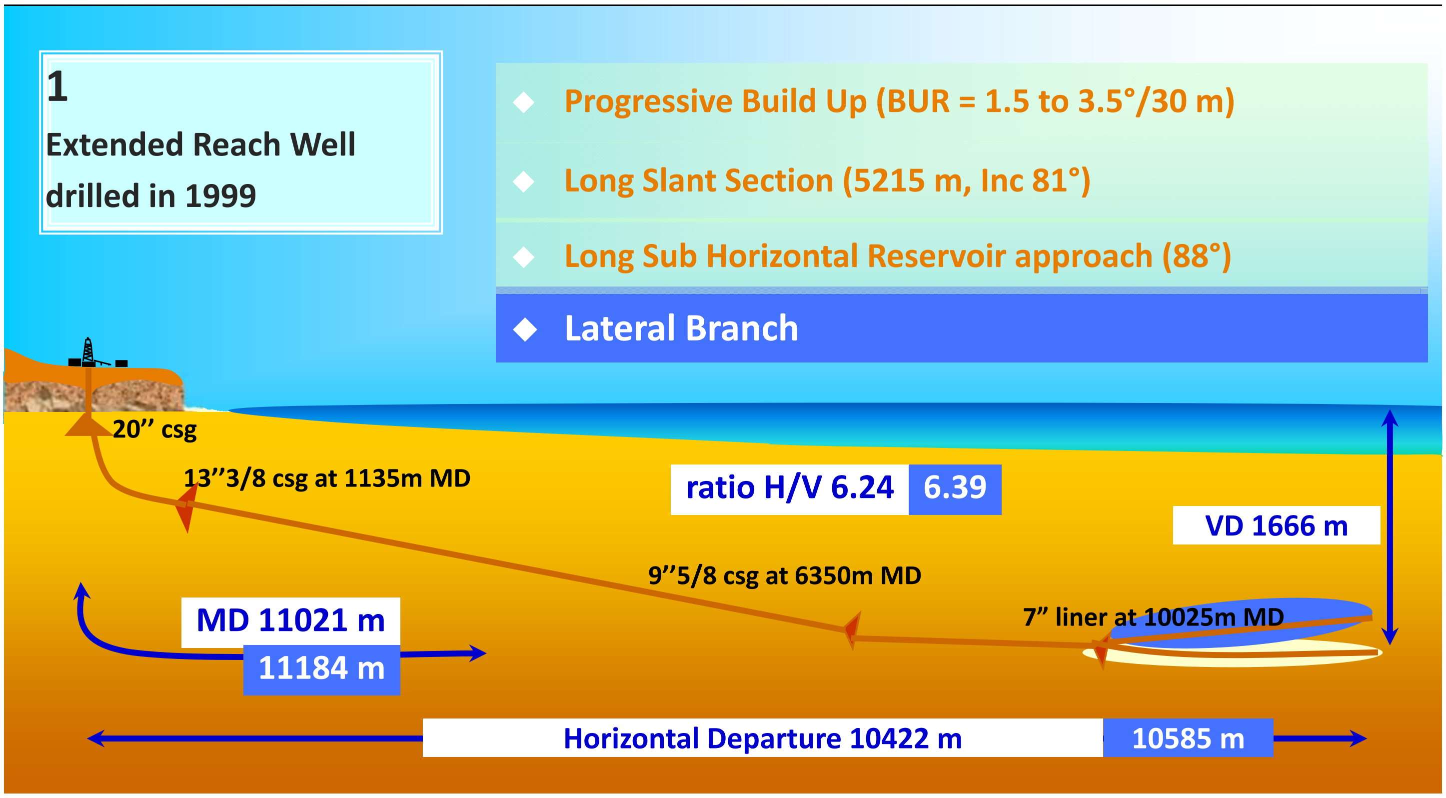


Hidra field – Tierra del Fuego
Argentina

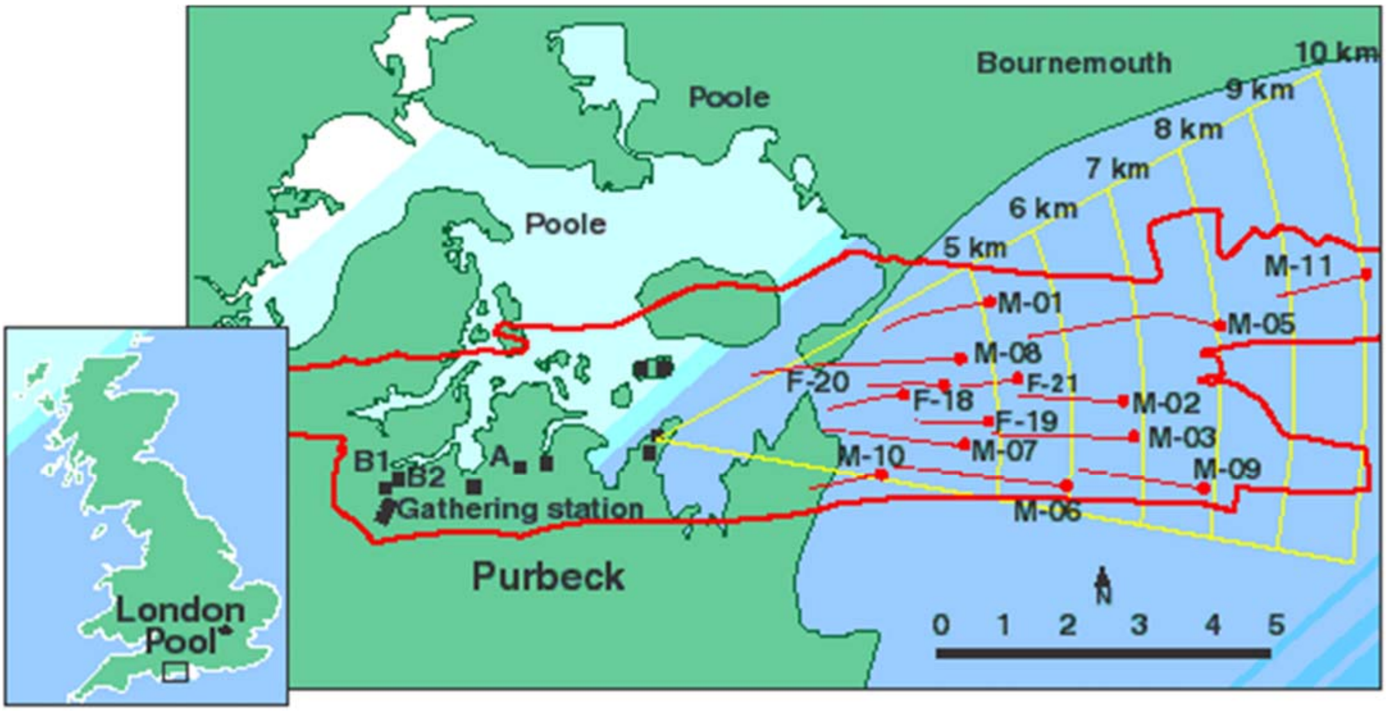
Source / Illustrations: TOTAL

« ERD wells »

(10+ km Departure)



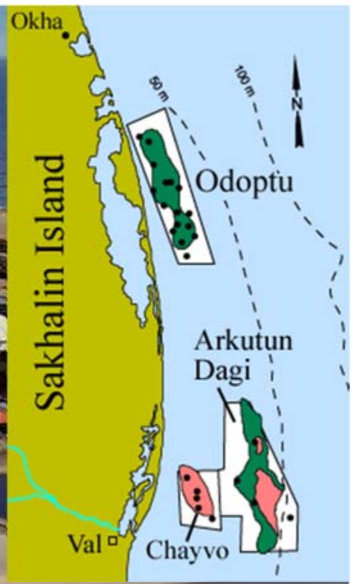
« ERD wells »



Extended reach well: Wytch farm field

« ERD wells » – Sakhalin 1 - Project

Early 2011,
Exxon Neftegaz – Sakhalin project
Well: OP 11 – Odoptu field
40502 ft (TMD); 37648 ft (departure)
Well duration (drilling) = 60 days!
Rig: Yastreb (Parker Drilling)



Source: internet

ExxonMobil

Key points to keep in mind

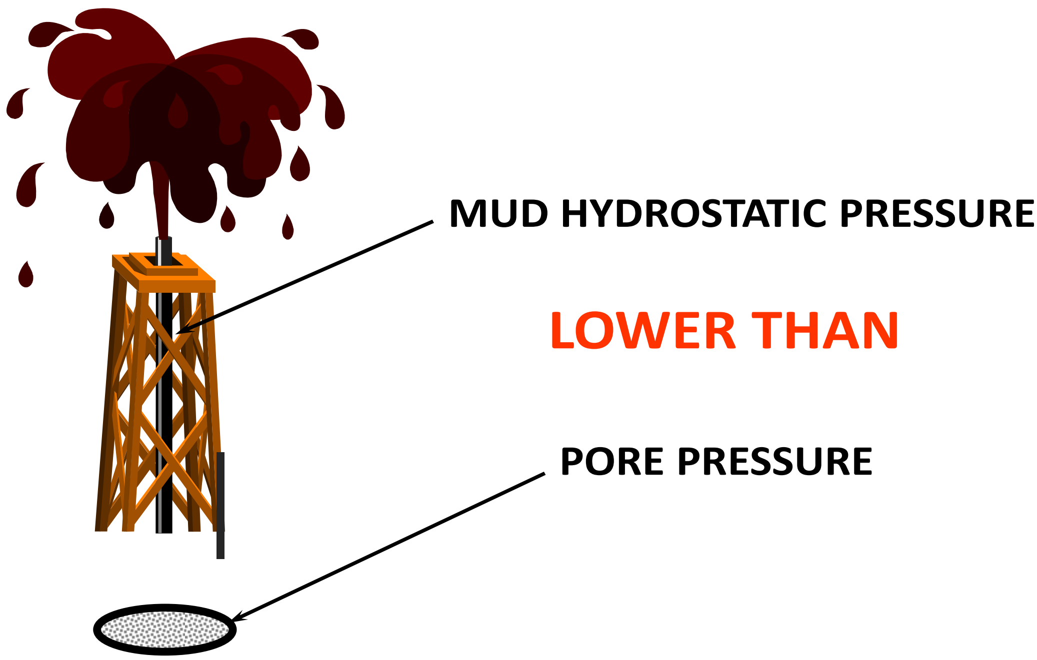
1. **Directional wells: terminology KOP, build up / slant / drop off sections, TVD, TMD, departure. Different well profiles**

2. **Drilling tools used for directional drilling: stabilized BHA, motors + bent sub, RSS tools**

3. **Advantages of horizontal wells**

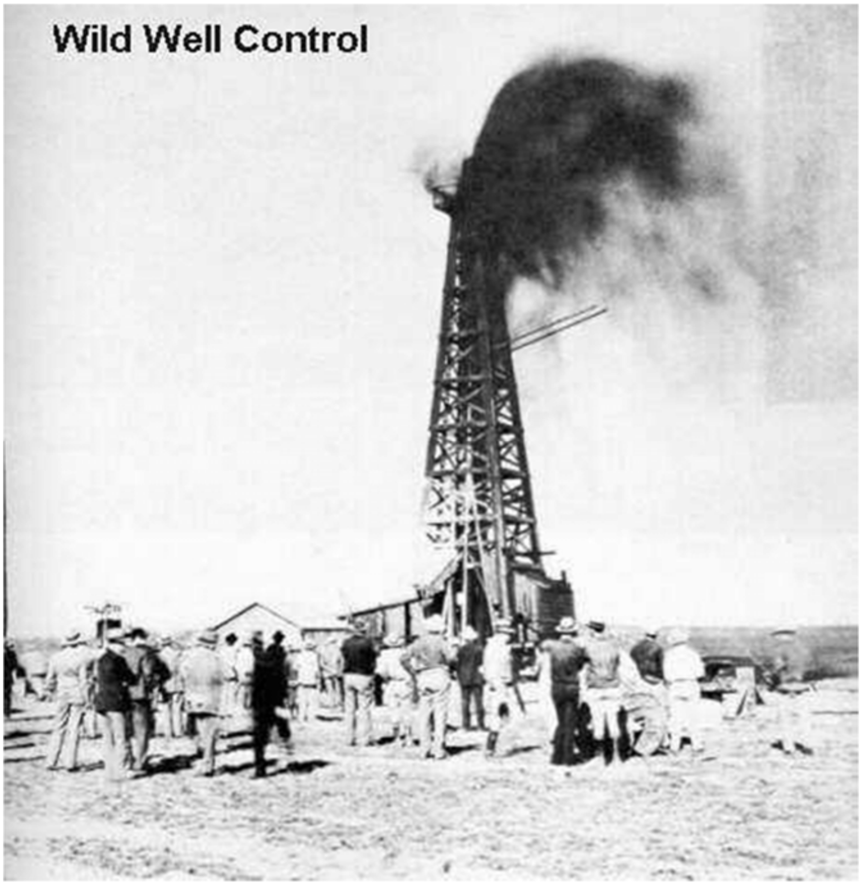
Blowout Prevention

Kick & blowout control



Well control

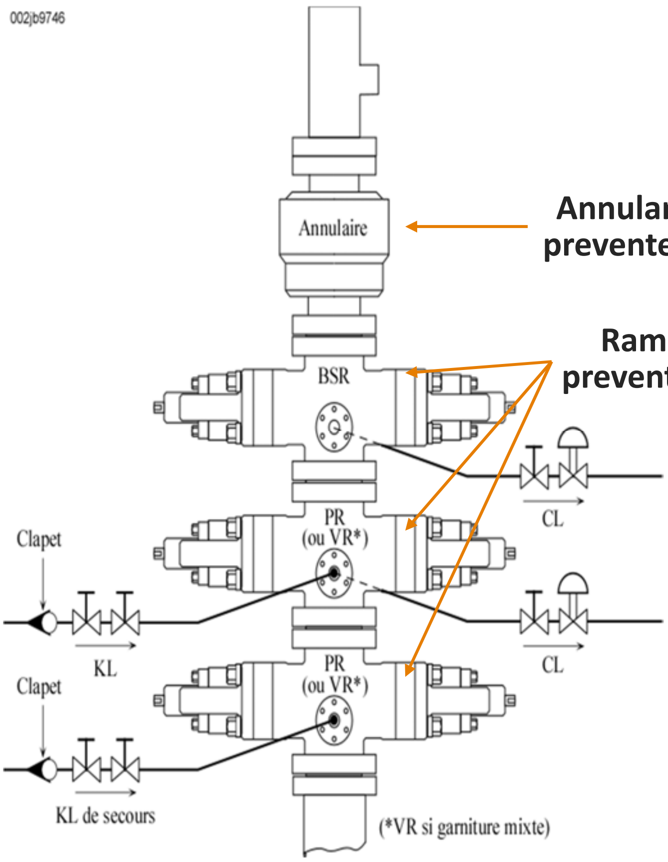
In early times, a blow out was the usual way to find oil (shallow wells with low pressure)!!



Well control

- While drilling, bottom hole pressure created by the mud column balances the formation pore pressure
- If not, an influx of the formation fluid in the well can take place (kick)
- Kick control procedures are then applied to safely displace the formation fluids up and out of the well
- If this is not correctly applied or fails, the situation may develop into an uncontrolled internal or external "Blow Out"
- Rule: two safety barriers must always be operational to avoid kicks and well control problems
  - Drilling fluid (SG, level…)
  - BOP control system/wellhead
  - Cement
  - Other (mechanical plug…)

Well control

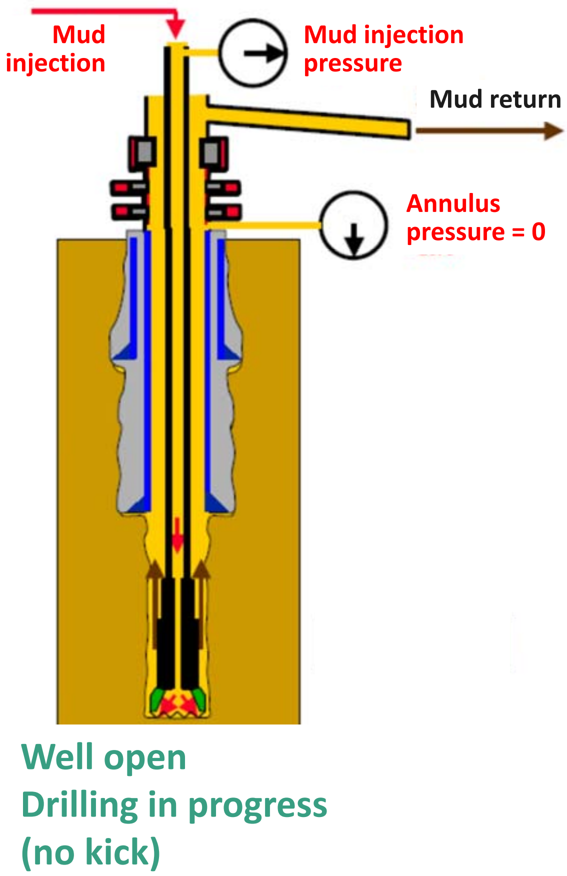


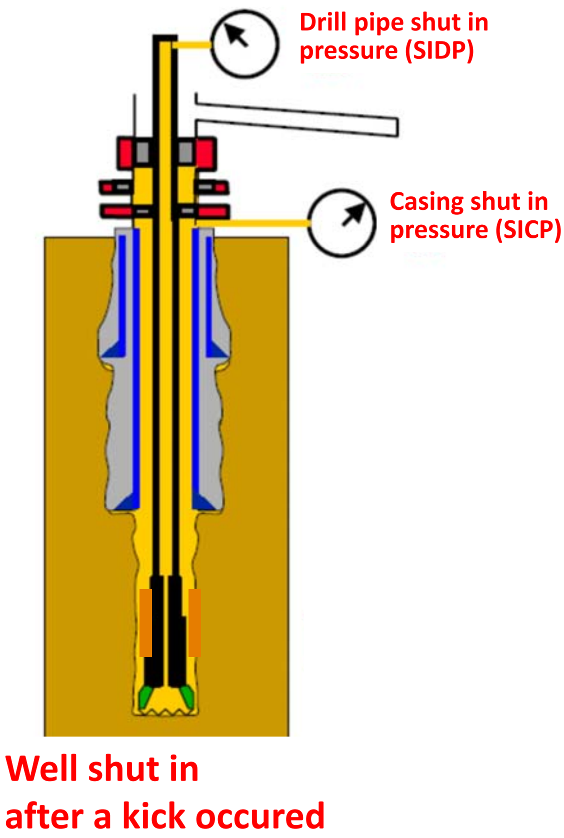
B.O.P. STACK

A set of blowout preventers controls the pressure in the well
The BOP stack is placed:

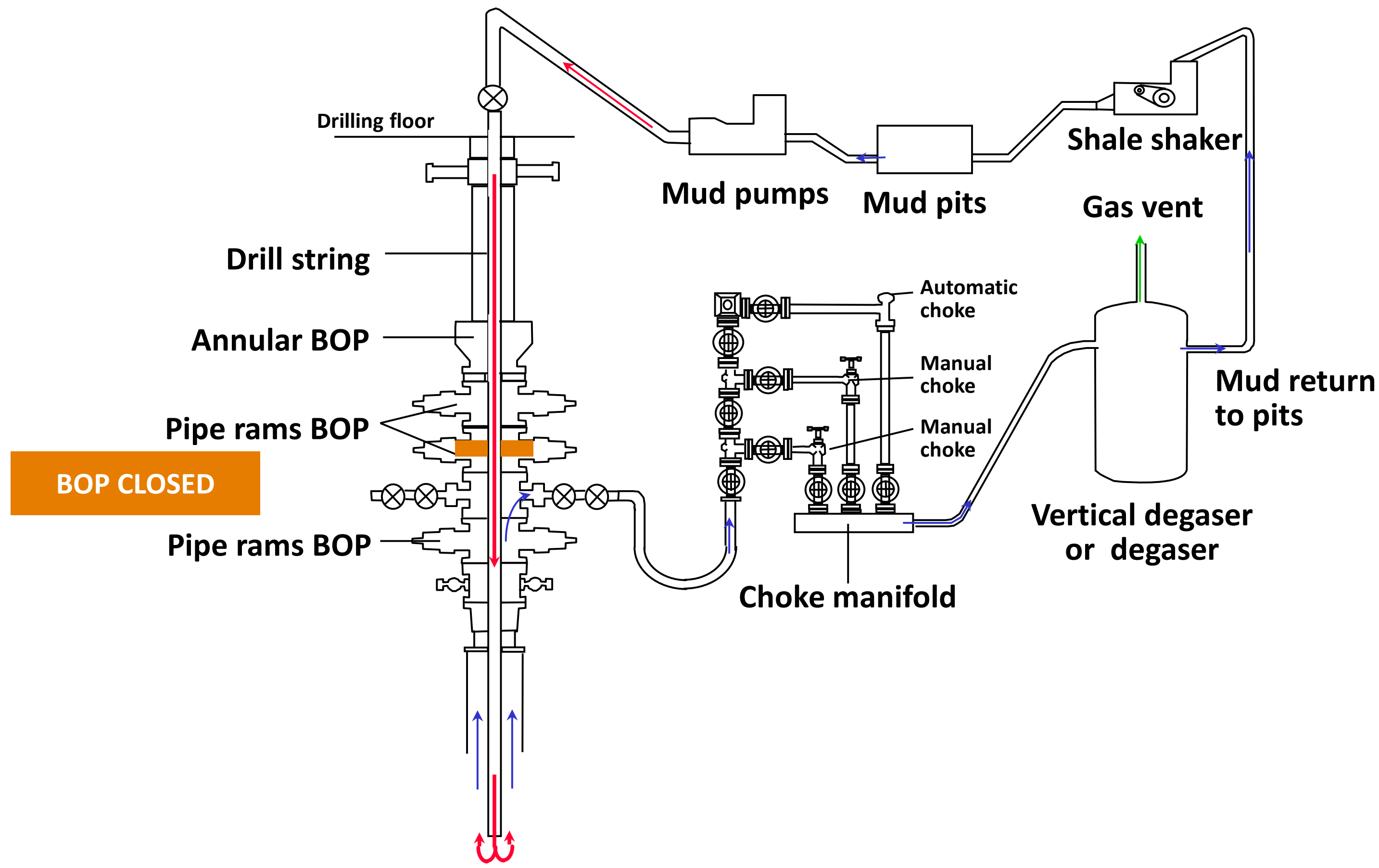
- below the rig floor (surface well)
- on the seabed (subsea well)

Well control





Well control circulation system

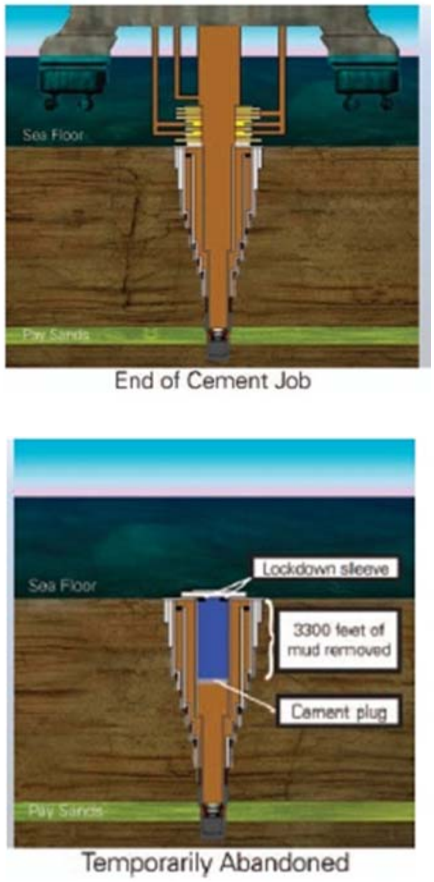


Deep Horizon accident

Sequence of events before blow out

- Cement job of the production liner with special slurry due to risk of losses into reservoir
- Check non return valve on float collar: considered as OK
- Replace mud in the riser by water to prepare for abandonment
- Close the BOP when hydrocarbons detected on surface

FIGURE 4.5: Temporary Abandonment



Key points to keep in mind

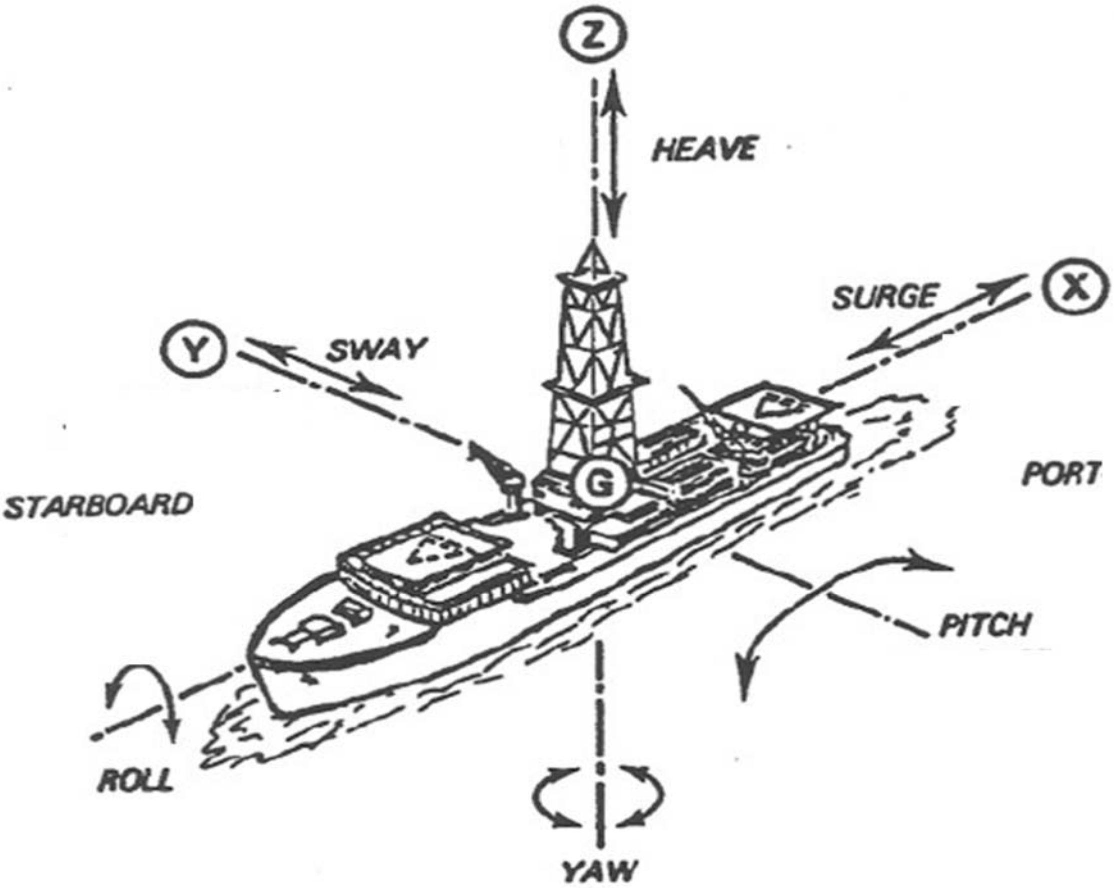
- **Principle of the safety barriers**
  - To have at all time two independent and tested well barriers after the surface casing is in place
  - If a barrier fails, no other activities shall take place in the well than those intended to restore the barrier
- **Types of BOP**
  - Annular type
  - Ram type
- **Functions of BOP**
  - Shut in well
  - Allow to circulate out an influx of formation fluid while keeping control of the well

Offshore Drilling

Contents

- Offshore environment
- Drilling units: specific equipment
  - Tensioning devices
  - Riser, telescoping joint
  - Subsea BOP and wellheads
  - ROV
- Drilling units vs. drilling projects
  - Drillships
  - Development projects
    - TLP
    - SPAR

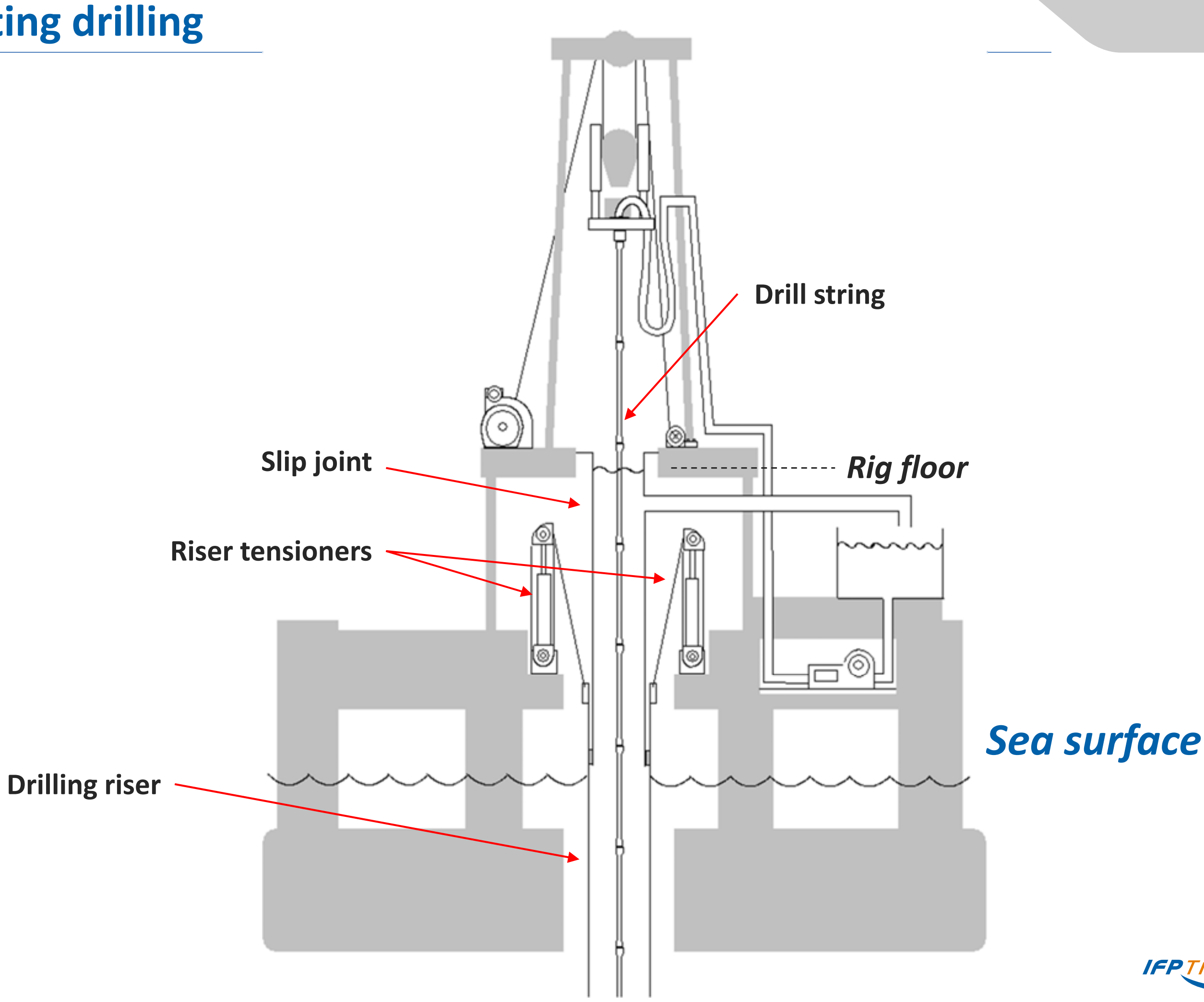
Floating platform motions



Offshore the rig is submitted to

- **The sea movements**
  - Heave
  - Roll
  - Pitch
- **The tide: water depth variation**
- **The marine currents amplitude and variation**
- **The general sea conditions that can be very hard (winds, storms, icebergs…)**

Floating drilling



Floating rig specific requirements

- **Casing hangers, BOPs and wellhead are located at the seabed**
- **Specific equipment required to connect the moving rig to the fixed seabed equipment**
  - Riser with telescopic joint
  - Ball joint, hydraulic connector
  - Riser active tensioning system
- **Specific equipment to compensate for the rig vertical movement while drilling and keep constant weight on bit**
  - Drill string heave compensator in derrick
- **Requirement for a station keeping system**
  - Anchoring system, or dynamic positioning system
- **Requirement for subsea observation equipment**
  - Camera, ROV

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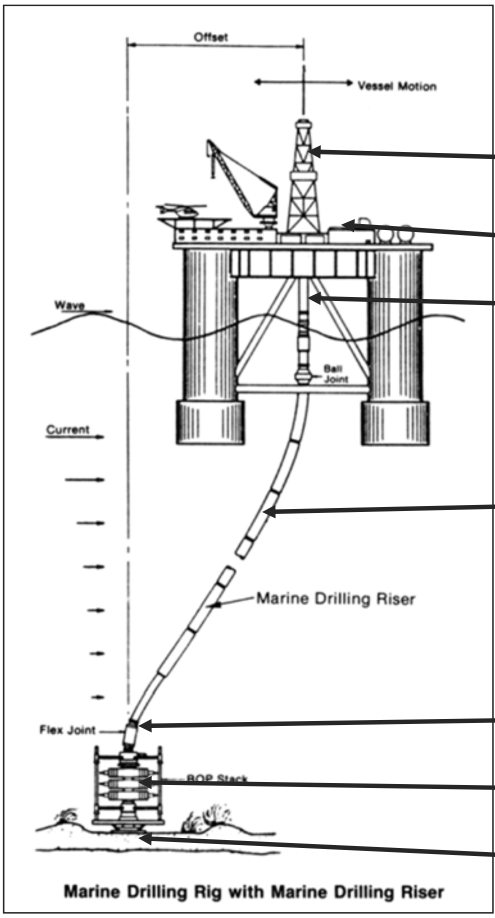
Specific subsea equipment for floating rigs



Heave Motion Compensator

Riser Tensioner

Telescopic joint

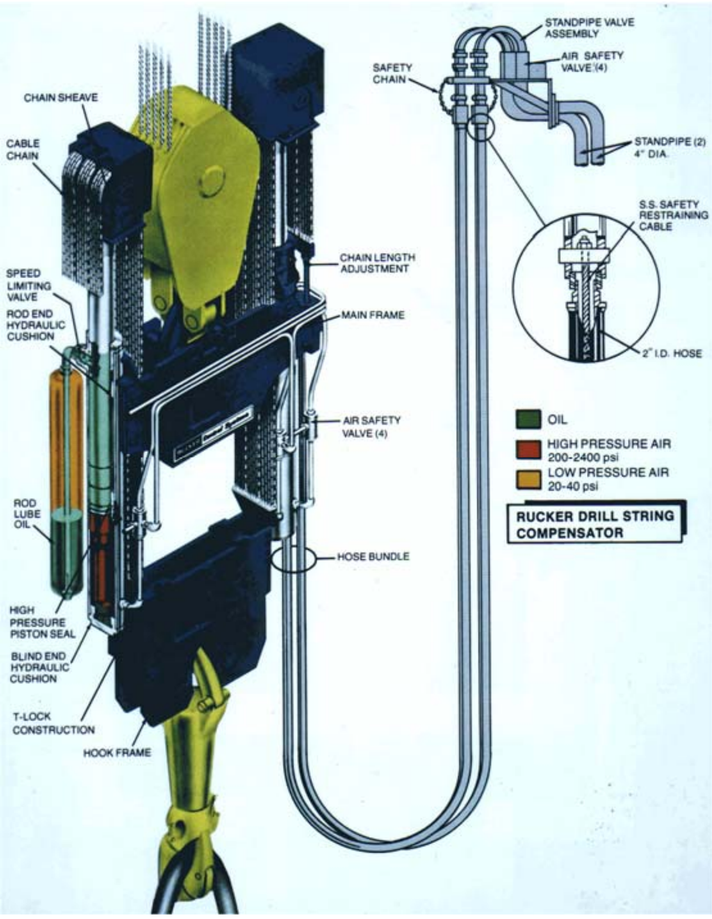
Marine drilling riser

Flex-joint

Subsea BOP stack

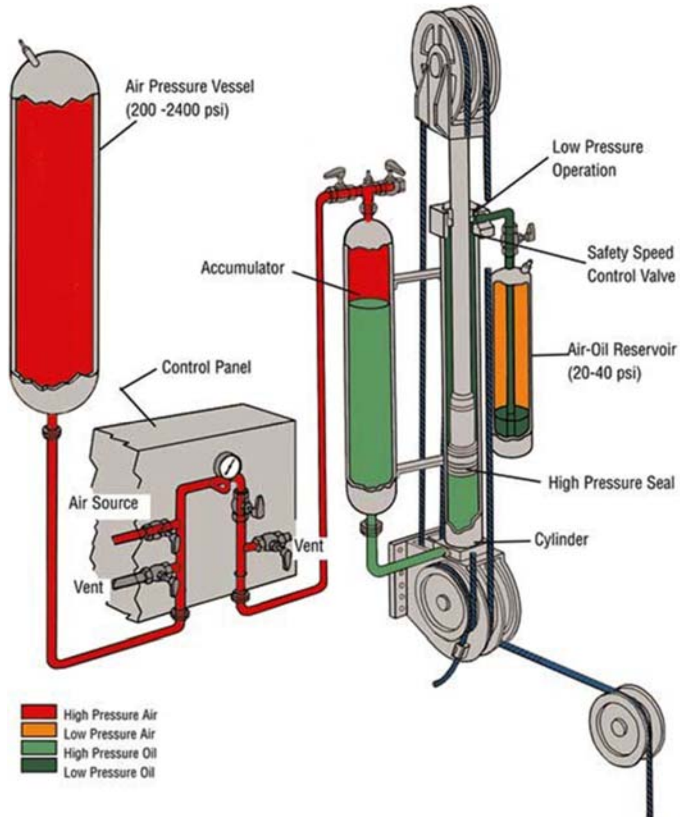
Subsea drilling wellhead

Heave compensator



Heave compensator to keep the Weight On Bit (WOB) constant

Drilling riser tensioning system

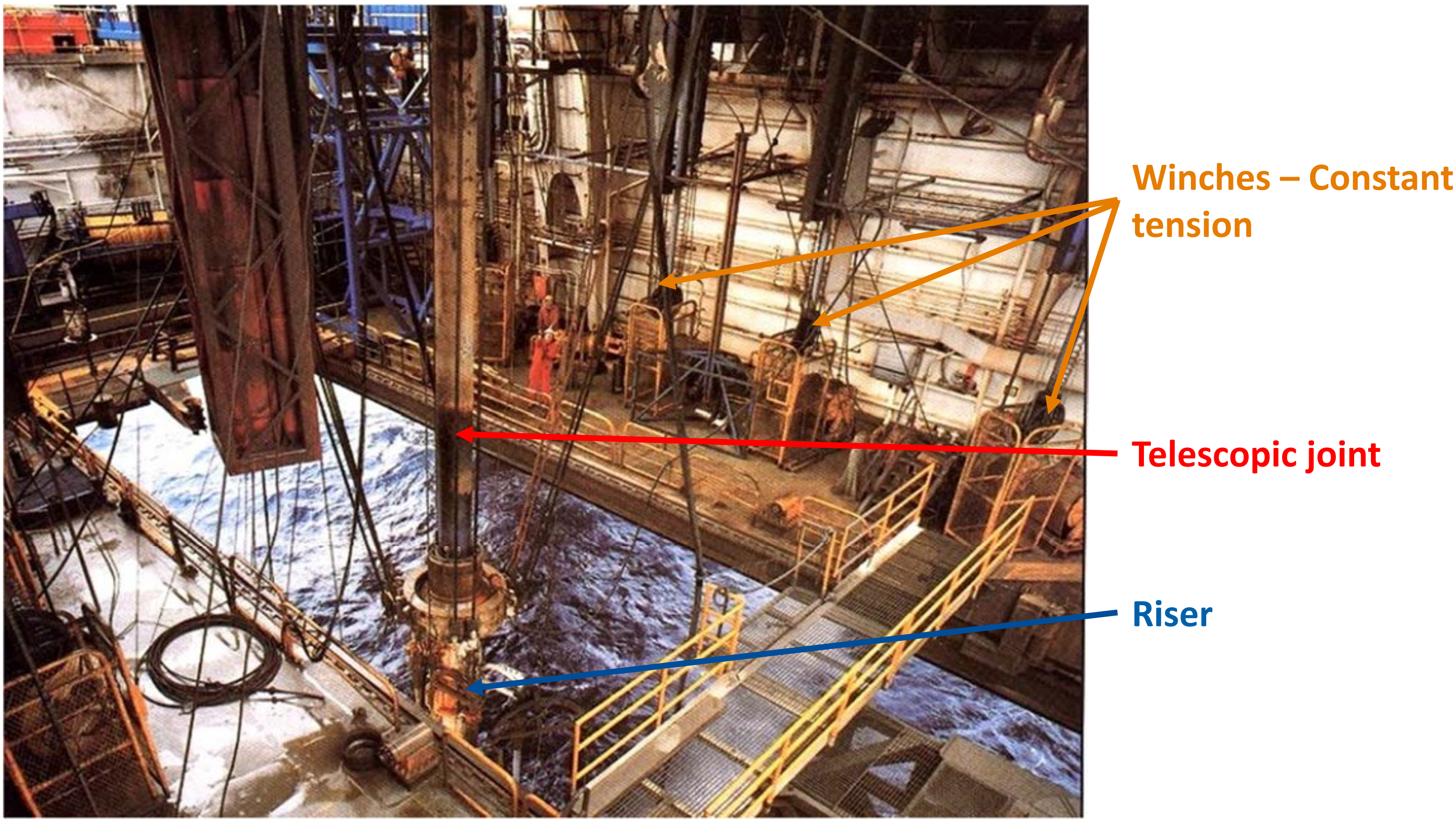


Riser tensioners to keep constant tension on the drilling riser

Contents

Drilling riser

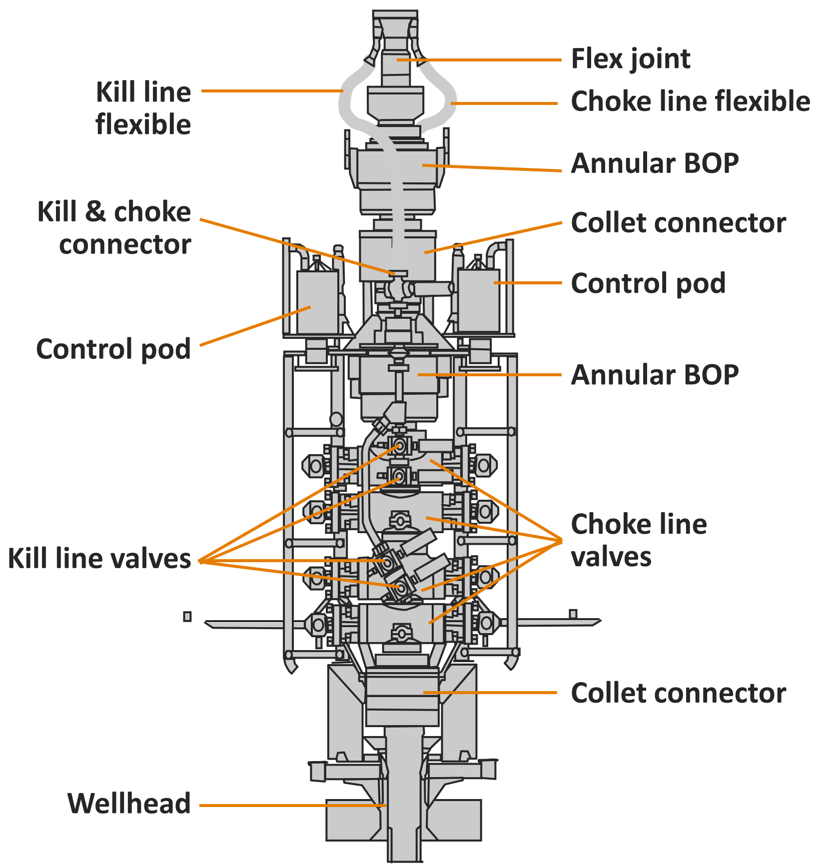
Suspension and tensioning of the drilling riser



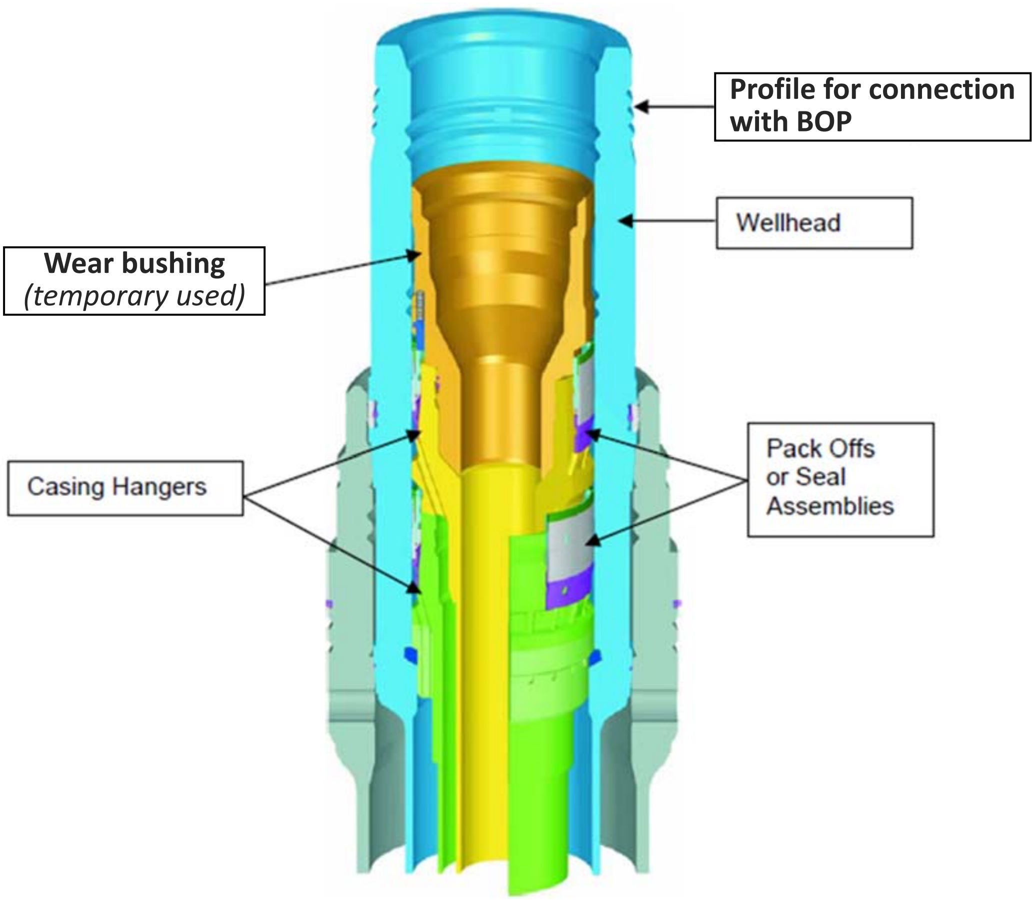
Offshore rough conditions

Contents

Subsea BOP stack



Subsea drilling wellhead



X-Mas trees (for production)

Vertical Tree
" Dual Bore Tree "

Horizontal Tree
" Spool Tree ™ "

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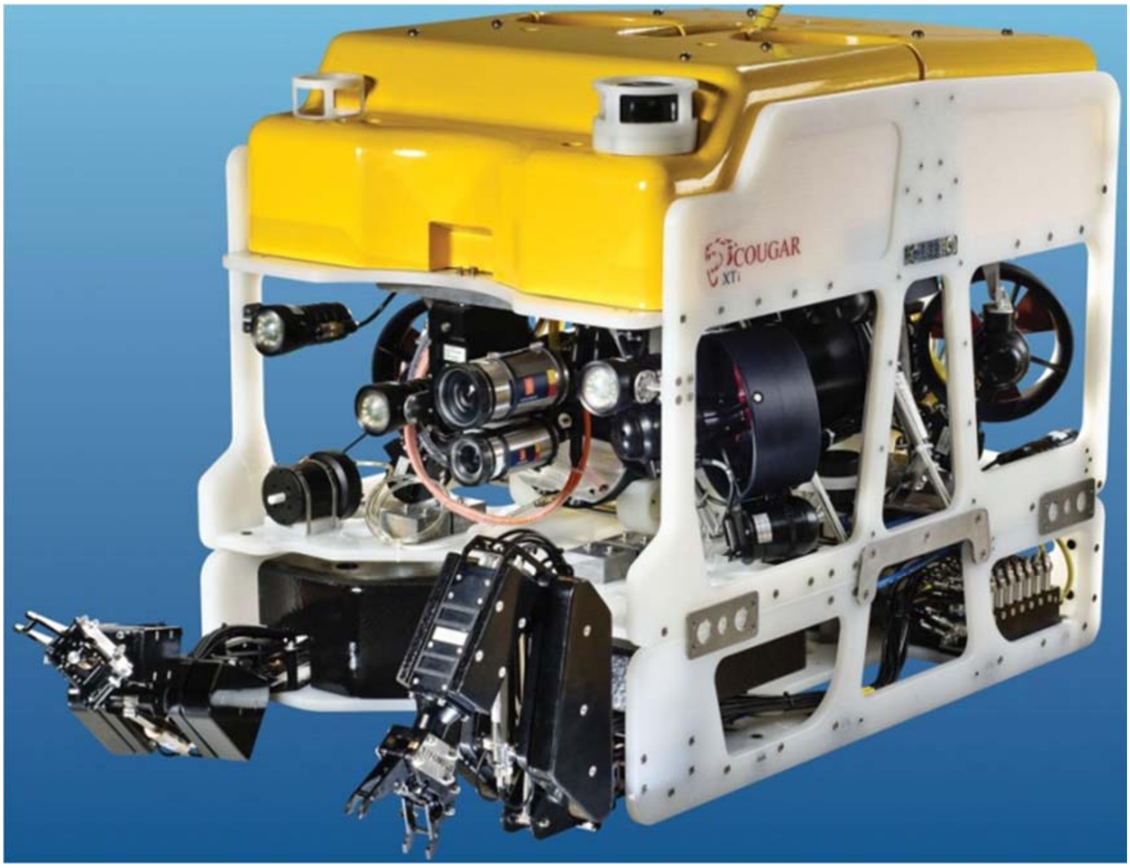
ROV for subsea observation and intervention

(* Remote Operated Vehicle)



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Offshore drilling units vs. applications to offshore projects

	Exploration / Appraisal		Development	
	Surface (Dry) Wellhead		Surface (Dry) Wellhead	
WD < 25 ft	Inland (Swamp) barges		Inland (Swamp) barges	
	Surface (Dry) Wellhead	Subsea (Wet) wellhead	Surface (Dry) Wellhead	
25 < WD < 350 ft	Jack-Up	Semi-submersible (WD > 200 ft)	JU or Tender or Compact rig	
	Subsea (Wet) wellhead		Surface (Dry) Wellhead	Subsea (Wet) wellhead
350 < WD < 1500 ft	Semi-submersible (conv. mooring)		Tender or Compact rig	Semi-submersible (conv. mooring)
	Subsea (Wet) wellhead		Surface (Dry) Wellhead	Subsea (Wet) wellhead
WD > 1500 ft	Semi-submersible or Drillship - Dypo mode		Tender or Compact rig	Semi-submersible or Drillship - Dypo mode

- **Other criteria for selection / application**
  - for exploration project: meteo-oceano survey, soil survey
  - for development project: surface/subsea trees vs. costs (Capex + Opex)

Contents

Semi-submersibles

Semi while drilling

Semi while moving

Semi-submersibles

To move, a semi sub will be generally towed or it can be loaded on a ship (for moving on long distances)

Some are self-propelling but their speed is very low

Semi-submersibles

Drillships

- All new drill ships are equipped with a dynamic positioning system

- Their stability is lower than the stability of a semi but their capacity is greater, and they can move faster

Drillships

DIMENSIONS	
Displacement	96,455 t
Length overall	228 m
Length between perpendiculars	219.4 m
Breadth, moulded	42 m
Depth, moulded	19 m
Operating draught, moulded	12 m
Transit draught, moulded	8.3 m

STORAGE CAPACITIES	
Fuel	42,500 bbls
Drilling water	18,157 bbls
Potable water	6,704 bbls
Mud (active & reserve)	12,300 bbls
Brine	3,000 bbls
Oil base mud	3,000 bbls
Bulk bentonite/barite	16,000 cu.ft
Bulk cement	18,500 cu.ft
Crude oil	140,000 bbls

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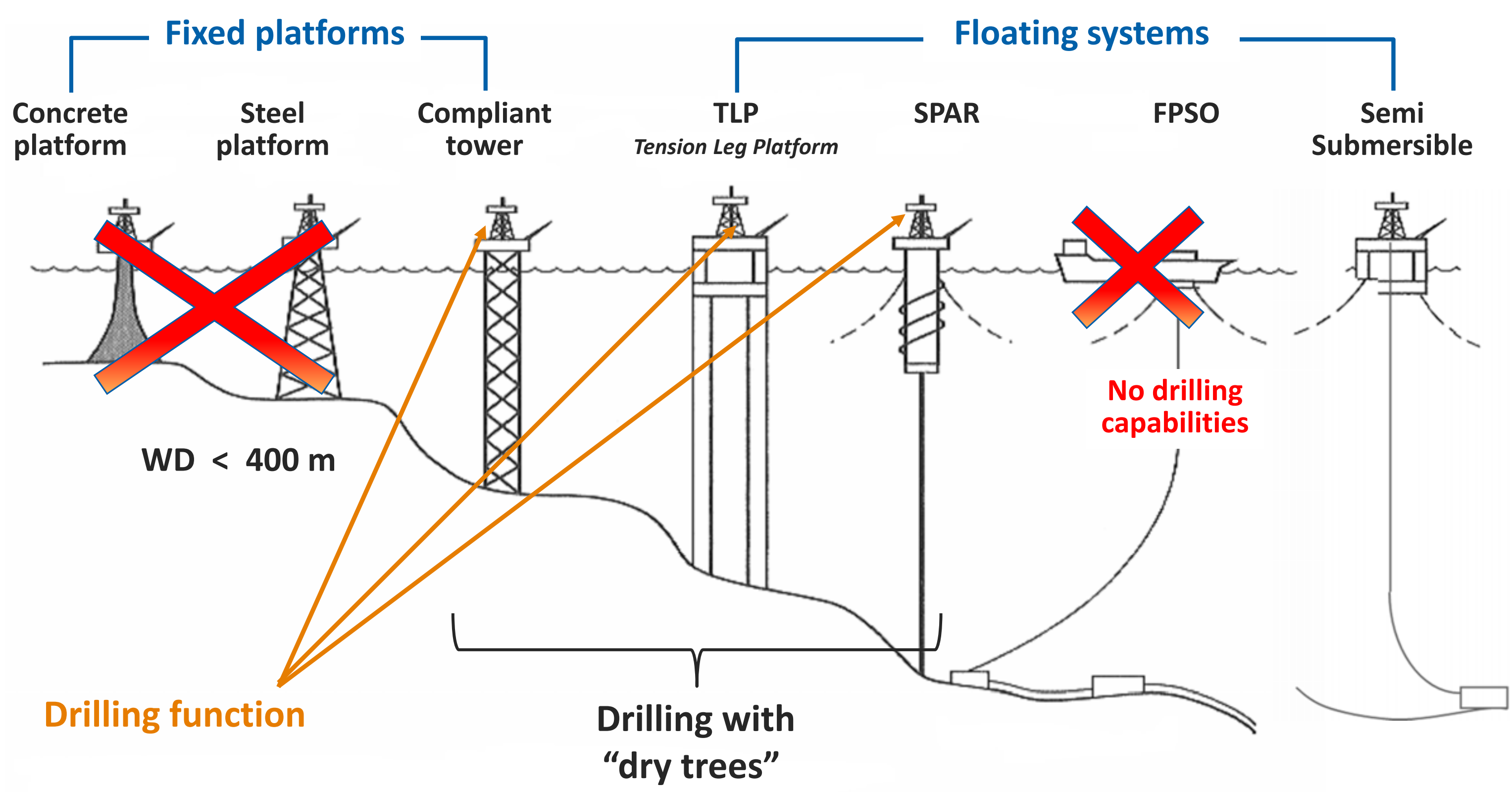
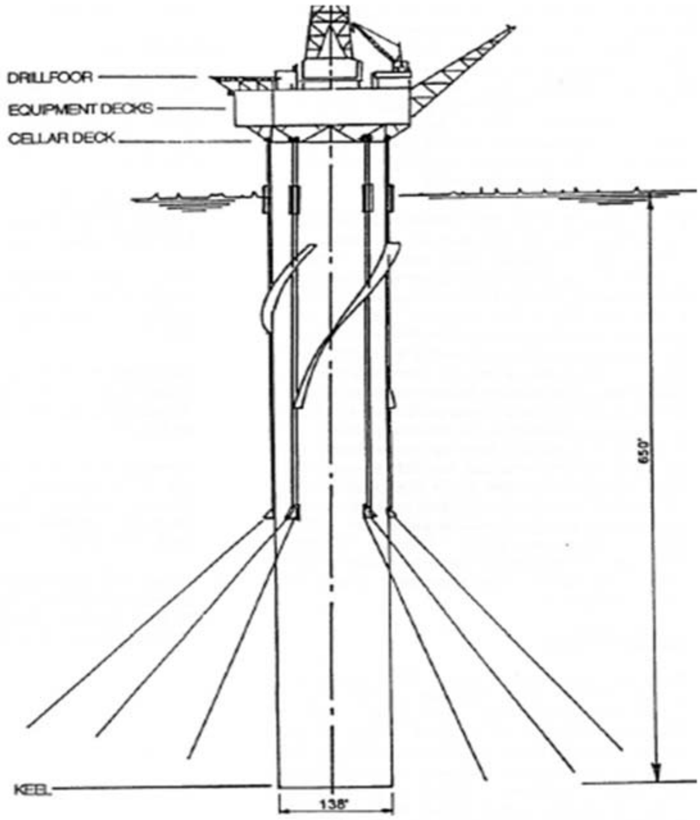
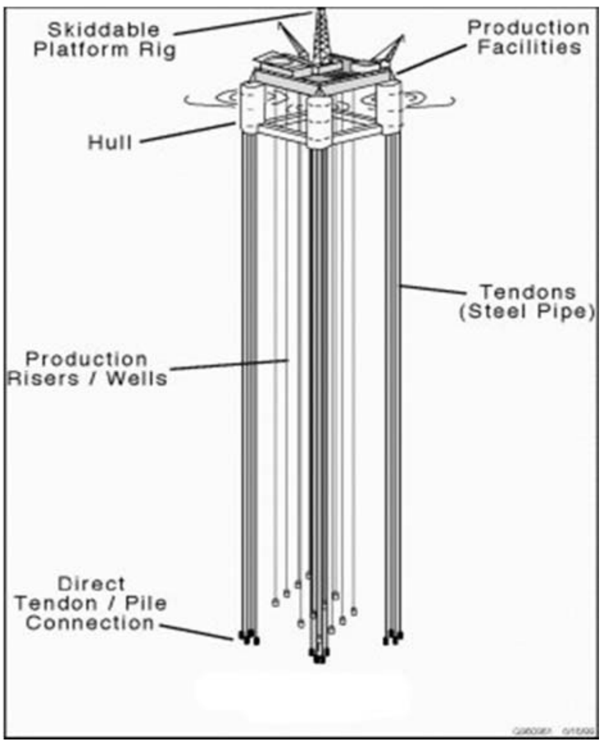


SPAR

- **Such platforms can accommodate:**
  - Full **drilling** / WO units: drilling rig operates through the center of the "cylinder"
- **Large catenary mooring**
  - To move the SPAR from one well to another (when applicable)



TLP (Tension Leg Platform)



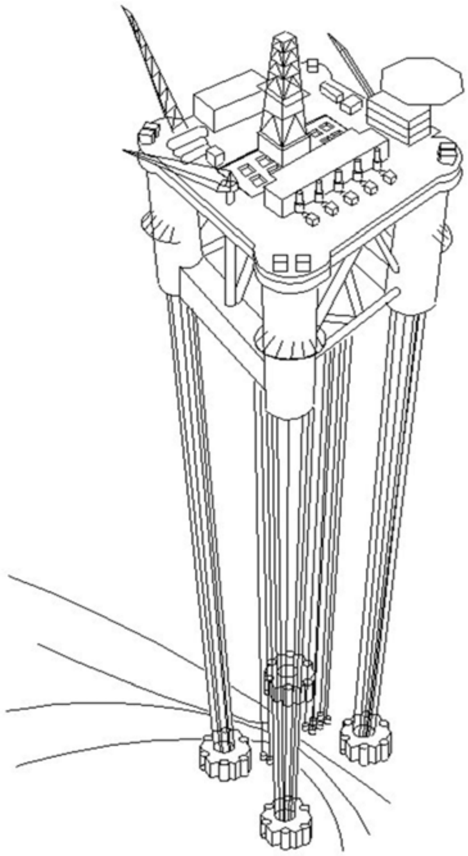


Figure 11 Tension leg platform

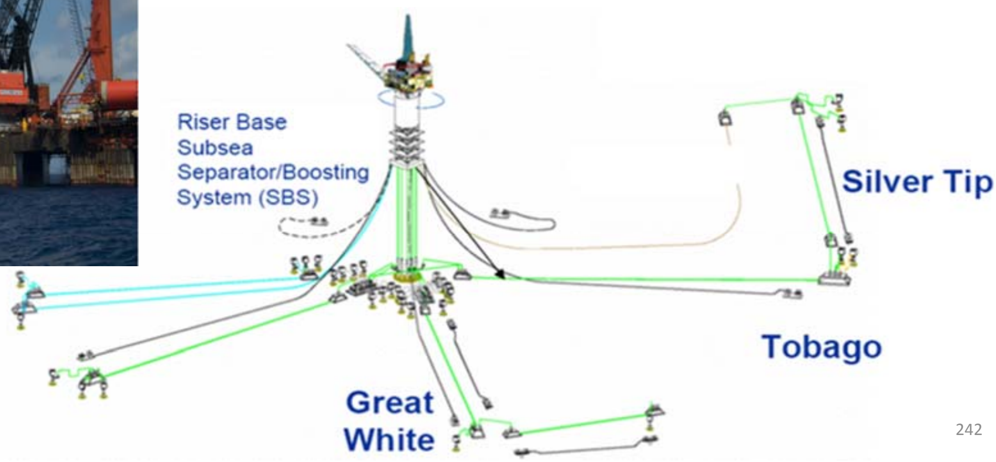
TLP (Tension Leg Platform)

Mini Tension Leg Platform

- **The Matterhorn field was wholly owned and operated by Total E&P USA**
- **The Company opted for an Atlantia SeaStar design of the type previously installed on such deepwater projects**
- **The Matterhorn field is located in MC Block 243 in the deepwater GOM, approx. 170km southeast of New Orleans. It lies in 850m of water**
- **The field came onstream in November 2003 and has a production capacity of 33,000 barrels of oil equivalent per day**
- **The Matterhorn platform is the first unit of this design to incorporate supporting vertical access production flowlines running through the central moonpool and controlled by surface (dry) trees**
- **Seven dry trees (predrilled) + 1 subsea for injection**

SPAR

- **Shell Perdido Host facility consists of a spar floating production platform with full drill, complete, and intervention capability**
  - Facility capacity will be 100,000 b/d and 200,000 cf/d
  - Nine polyester mooring lines averaging more than 2 miles (3 km) in length now hold the 50,000-ton floating structure in place, which will be nearly as tall as the Eiffel tower



SPAR in tender assisted mode (WD: 1300 m)

“KIKEY” field development

“KIKEY” field
(Murphy – Petronas / E.Malaysia)

FDPSO unit

A FDPSO unit, for deepwater, small and remote field development

Prosafe-Azurite is the world's first Floating Drilling Production Storage Offloading (FDPSO) unit, in operation in the Mer Profonde Sud block (Azurite field, WD 1400 m), operated by Murphy West Africa Ltd, off the Democratic Republic of Congo.

Key points to keep in mind

- Offshore environment: geohazards and impact on the rig behavior
- Specific drilling rig equipment for floaters (semi-sub and drillships)
- Use of offshore drilling units vs. Offshore drilling projects

Well Productivity & Wellbore Interface

PPLCTE

IFP Training

Contents

Well completion

Contents

- Concerned area
- Completion design
- Main types of completion configuration

Concerned area

Well completion: Concerned area

To "complete" a well:

- The hole being made by a driller
- To put it in production
- Taking the reservoir conditions into account

⇒ Well completion:

- Crossroad between:
  - drilling
  - reservoir engineering
  - production

Well completion: Concerned area

= **To make the well produce for the first time:**

- Drilling in the producing formation
- Connecting the pay-zone and the borehole
- Treating the pay-zone
- Equipping the well
- Putting the well on stream
- Assessing the well

RWI (reservoir-wellbore interface)

\+ **Operations on the well at a later date:**

- Measurement
- Maintenance
- Workover

Well completion: Concerned area

Greatly influenced by:

- The way the well has been designed and drilled
- The production problems the reservoir might cause

⇒ **Work in close collaboration with:**

- The driller
- The reservoir engineer
- The production staff

Main factors influencing completion design

Parameters related to well purpose:

Exploration well

- **Prime objective:**
  - To prove the presence of oil or/and gas:
    - Nature and characteristics of the fluids in place in the reservoir (including the water)
- **Other objective:**
  - To know the characteristics of the pay-zone:
    - Initial pressure and temperature
    - Approximate permeability and productivity
- **Means:**
  - Wireline logging
  - Test string

⇒ **Decision to develop or not**
Well suspended or abandoned

Parameters related to well purpose (cont.):

Confirmation well (or appraisal or delineation)

- **Objectives:**
  - To refine the results from the exploration well:
    - Strictly representative sample
    - Pressure, permeability and well productivity
  - Determination of the off wellbore reservoir characteristics:
    - Off wellbore permeability
    - Heterogeneity, discontinuity, faults
    - Reservoir boundaries, possible water drive
- **Means: well testing**
  - Designed with the help of knowledge from the exploration well
  - Usually more complete

  ⇒ Longer duration for the testing

Parameters related to well purpose (cont.):

Development well

- **Types of development wells:**
  - Production wells
  - Injection wells
  - (Observation wells)
- **Objective (depending on the well type):**
  - To produce the reservoir
  - To inject fluid to maintain pressure or create a sweeping effect
  - (to run some measurement tools)
  - ⇒ Flow potential
- **Note: importance of testing to:**
  - Assess the condition of the well
  - Obtain further information about the reservoir

Parameters related to environment

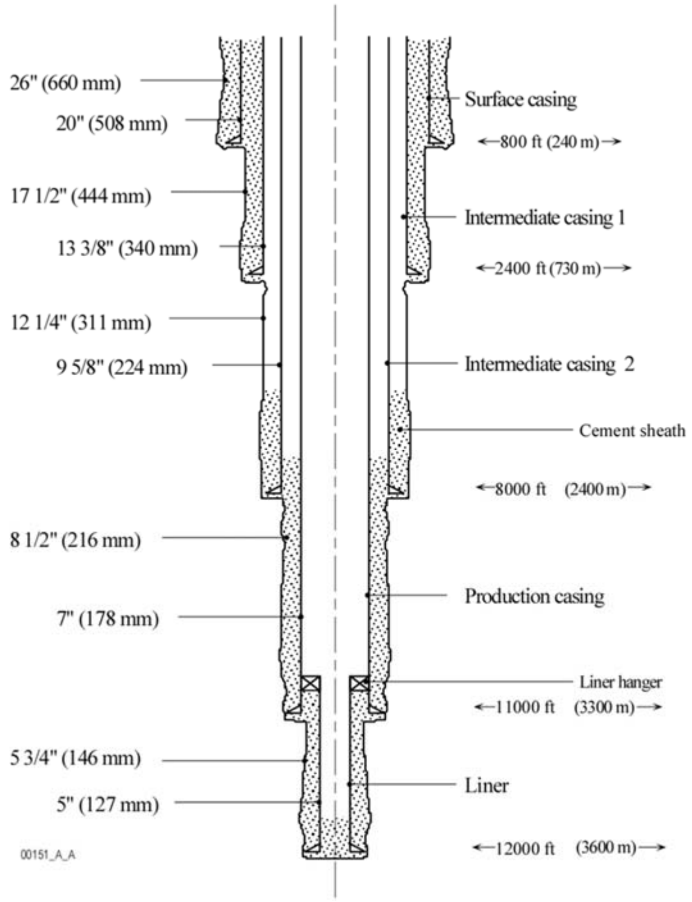
- Area, Country
- Well location
- ....

⇒ Constraints

Parameters related to drilling

- Drilling rig used
- Well profile
- Drilling and casing program*
- Drilling in the pay-zone(s) & drilling fluid:
  - Formation damage ⇒ prevention
    restoration
  - Other considerations
- Cementing the production casing

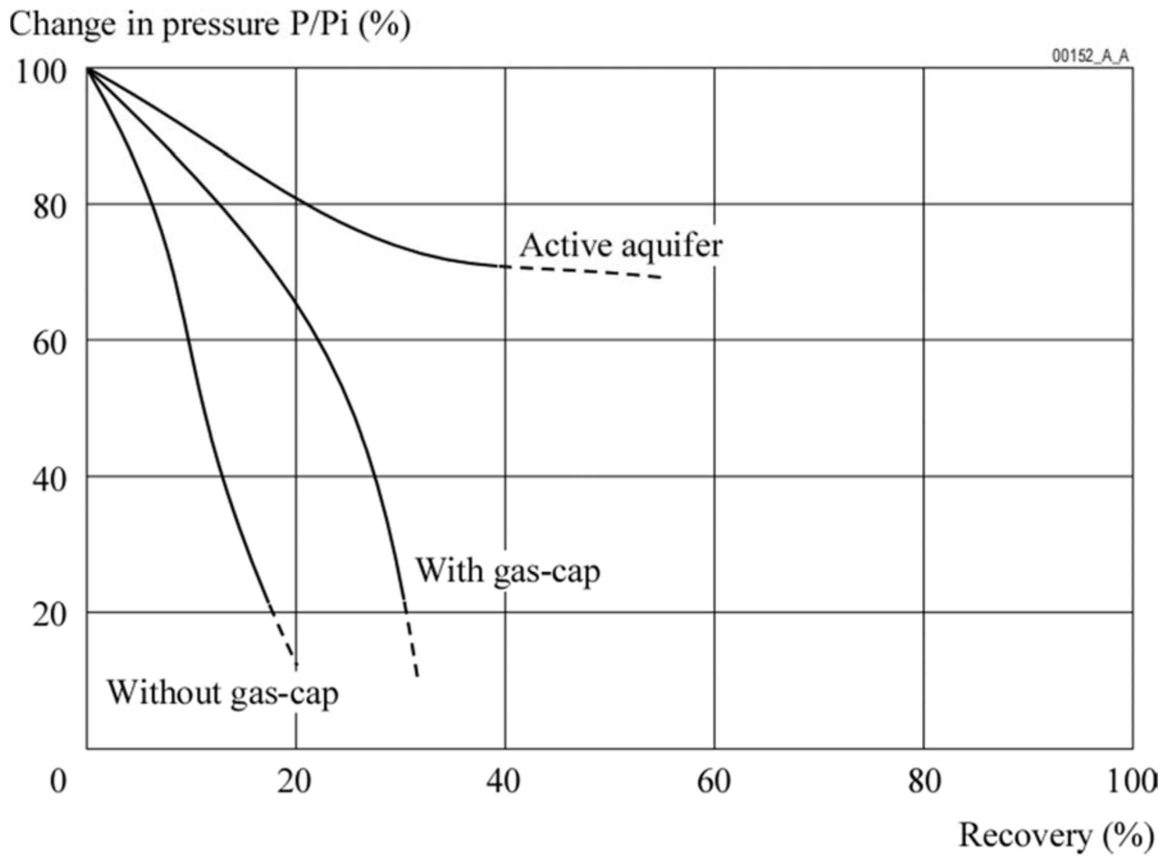
Available diameters according to the drilling and casing program



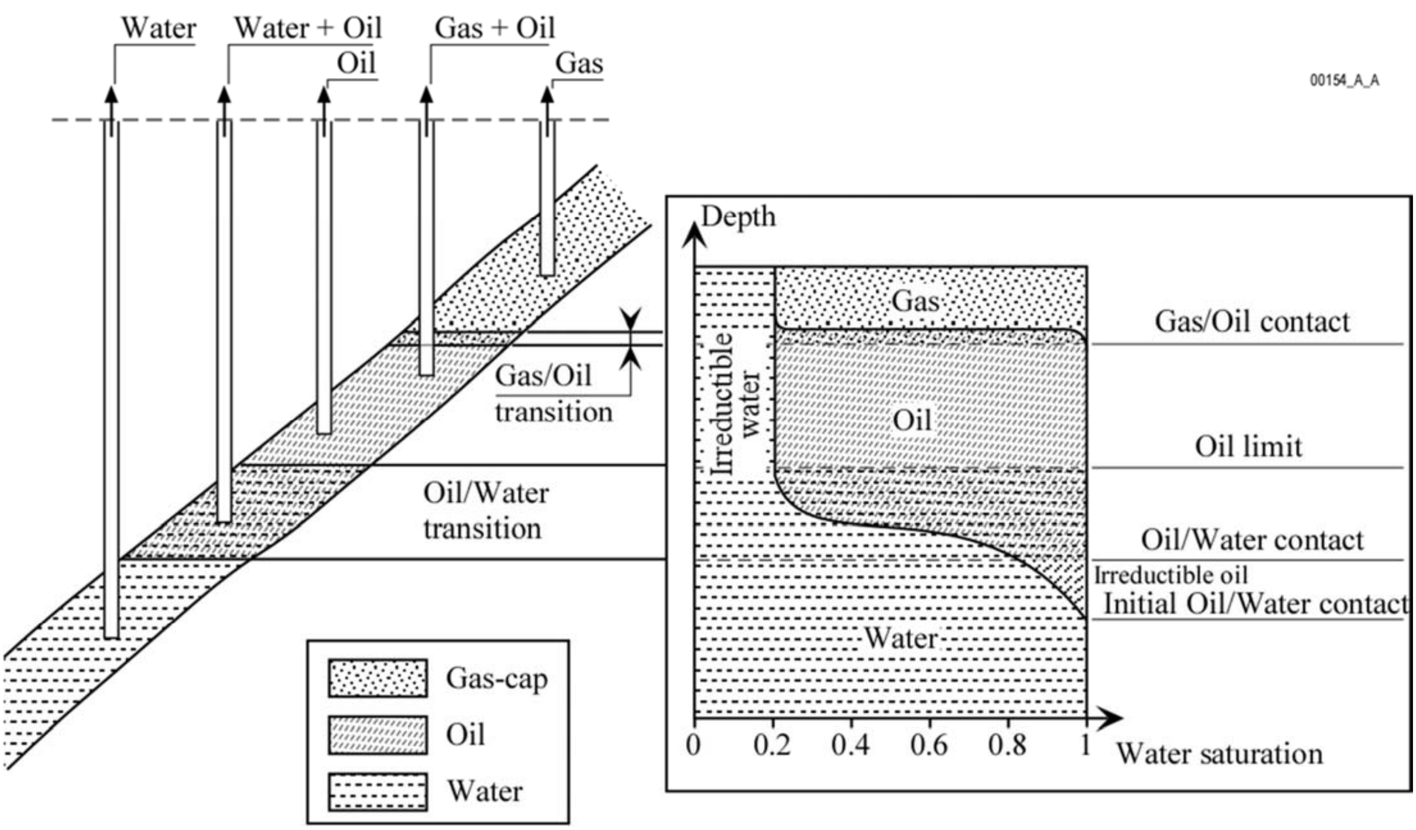
Parameters related to reservoir

- **Reservoir pressure and its changes***
- **Interfaces between fluids and their changes***
- **Number of levels to be produced**
- **Rock characteristics & Fluid type**
- **Production profile & Number of wells required**

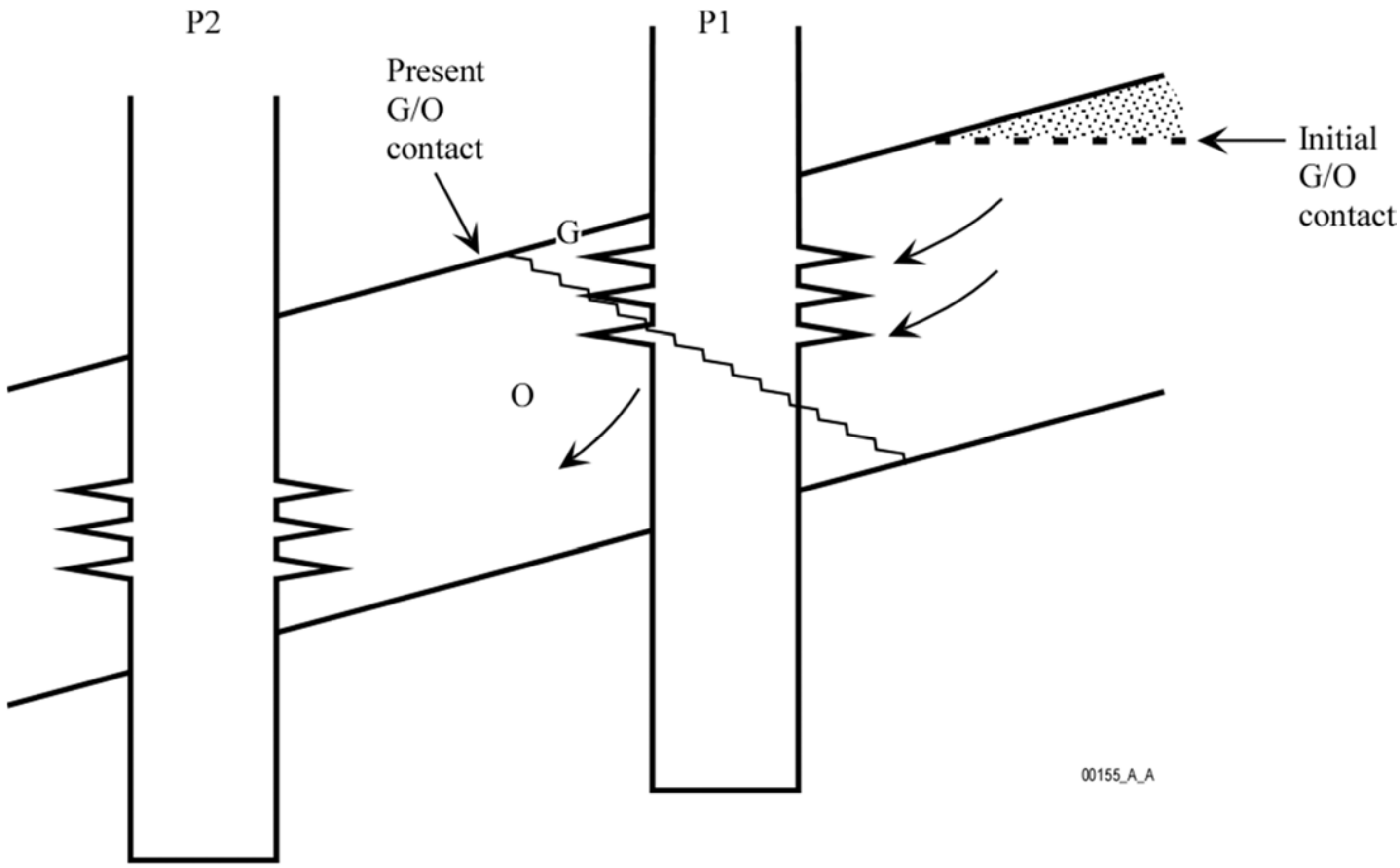
Change in the reservoir pressure versus cumulative production



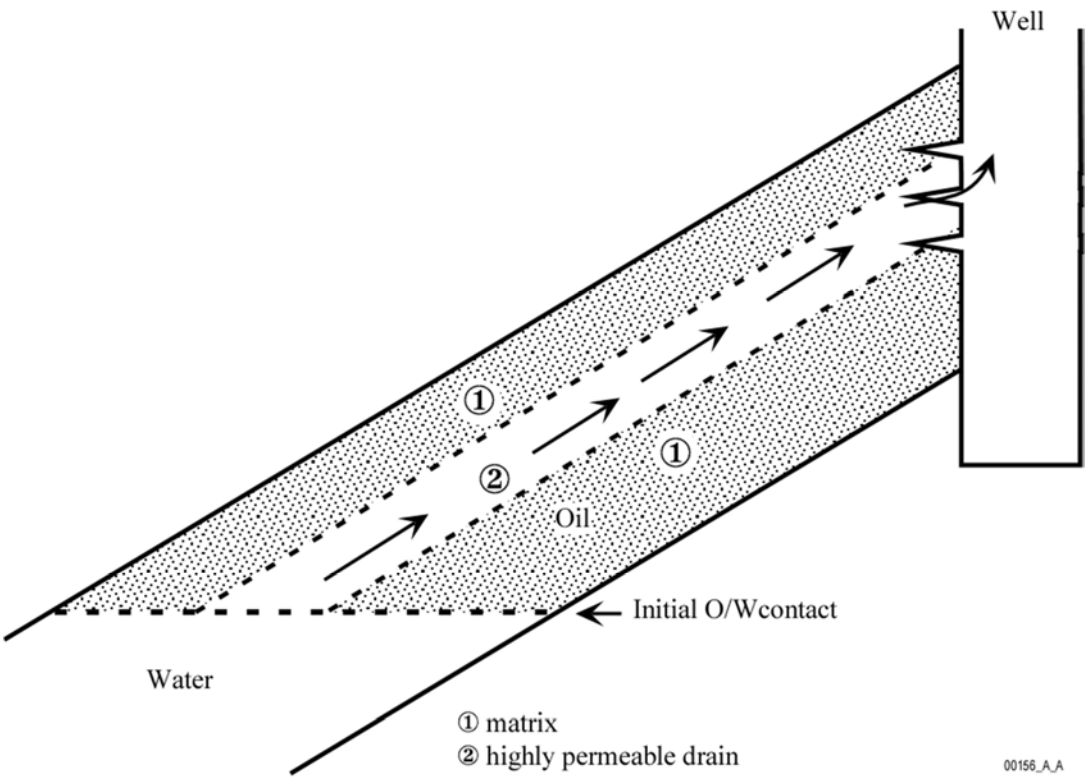
Fluid distribution in a homogenous reservoir



Interface change with cumulative production



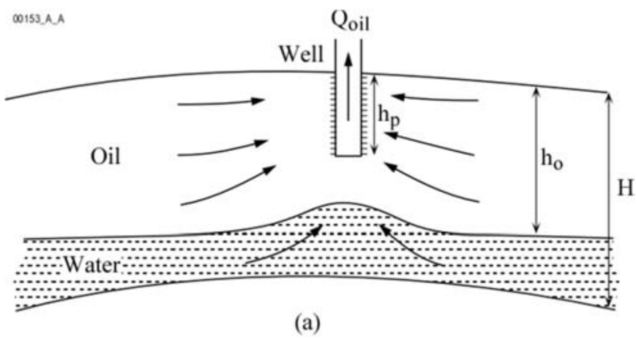
Influence of a highly permeable drain on a W/O contact

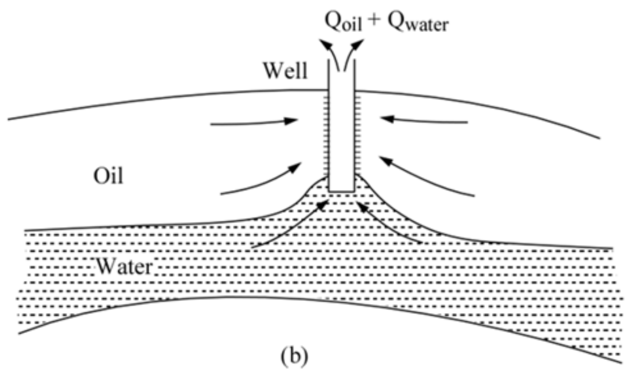


Coning

a) Stable cone

b) Water encroachment in well





H: **Pay zone thickness**

h_o: **Thickness occupied by oil**

h_p: **Well penetration**

Parameters related to production

- Safety
- Flowing well or artificial lift
- Operating conditions
- Anticipated measurement, maintenance or workover operations

Parameters related to completion technique

- Interdependent choices
- Function of the other parameters

=> Compromise

Completion techniques ?

Completion design

- **From the main purposes decided by:**
  - The company operation management
  - The reservoir engineering department
- **As:**

  For exploration or appraisal well:
  - Level to be tested
  - Type of test
  - ...

  For development well:
  - Level(s) to be produced
  - Production profile
  - ...

Completion design (cont.)

- **The problem is to design the best possible completion in order to:**
  - Optimize productivity (or injectivity)
  - Ensure reliability and safety
  - Optimize equipment lifetime
  - Be able to adapt the well to future change
  - Minimize costs (investment, operating, workover)

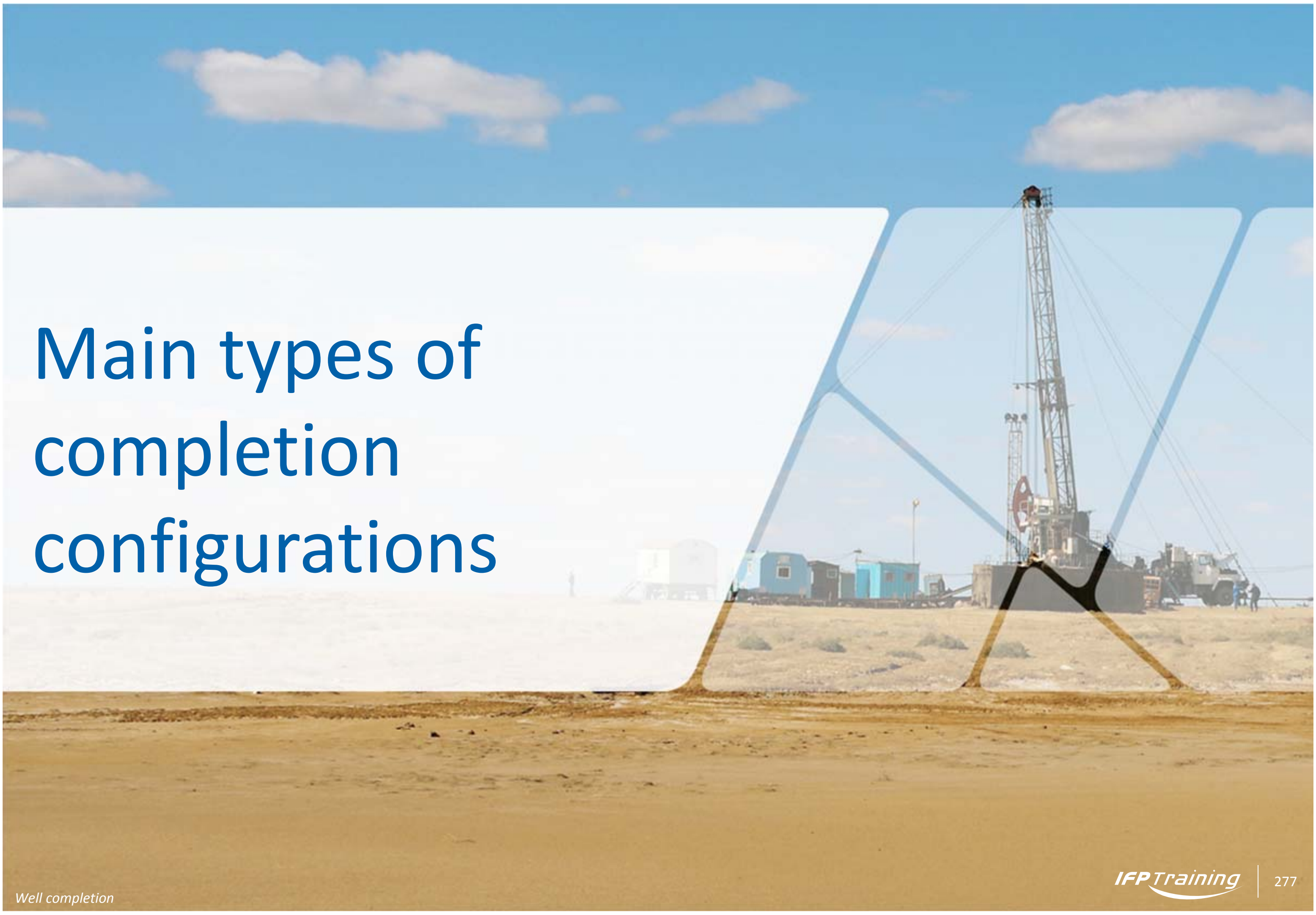
  ⇒ **Compromise or modified purposes**

Completion design (cont.)

- **Main constraints**
  - Local constraints
  - Effluent characteristics
  - Reservoir characteristics
  - Number of producing formations
  - Available diameter, borehole profile
  - Necessity for treatment operations
  - Necessity to maintain reservoir pressure, for artificial lifting
  - Later operations

Completion design (cont.)

- **Importance of data collection**
- **But the job is not easy since data are:**
  - Very numerous
  - Sometimes tardily known
  - Sometimes contradictory
  - Negociable or not



Main types of completion configurations

Contents

Preamble

Main parameters for completion design (reminder)

- Type of well:
  - Exploration
  - Confirmation or appraisal (or delineation)
  - Development
- Well purpose:
  - Production
  - Injection
  - Observation
- Production way:
  - Naturally flowing well
  - Artificial lift
- Interface between fluids
- Number of zones to be produced:
  - (all together)
  - separately
- Anticipated measurement, maintenance or workover operations

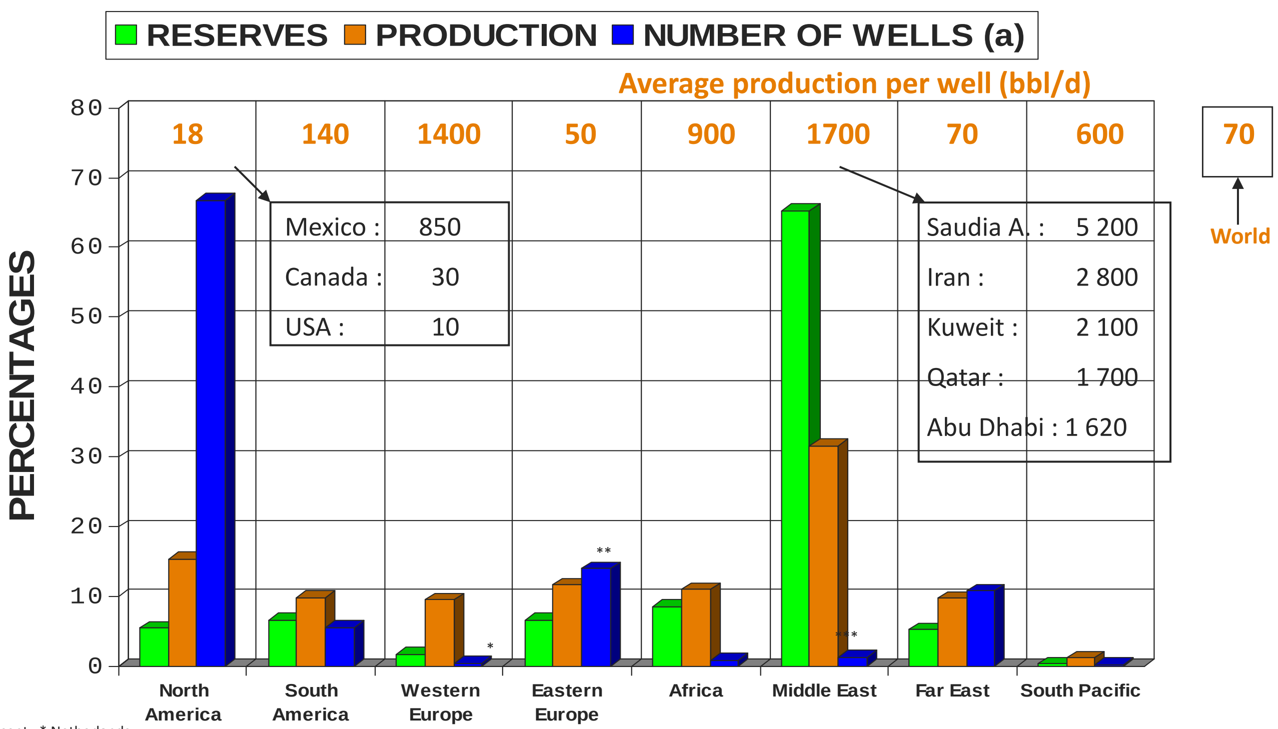
Objective

- To choose the best suited configuration:
  - Greatest possible flow potential
  - At the lowest cost

  ⇒ Compromise
- Compromise taking into account:
  - Costs:
    - Capital expenditure (CAPEX)
    - Operating expenditure (OPEX)
  - Relativity
  - Anticipation

  and also:
  - Flowrate per well*
  - Risks:
    - In relation with the flowrate
    - In relation with safety
  - Cultural factor

Statistics on oil production (end of 2000) (from World Oil august 2001)



(a) except : * Netherlands
** countries of ex-URSS other than Russian Federation
*** Iraq

Basic requirements

Basic requirements

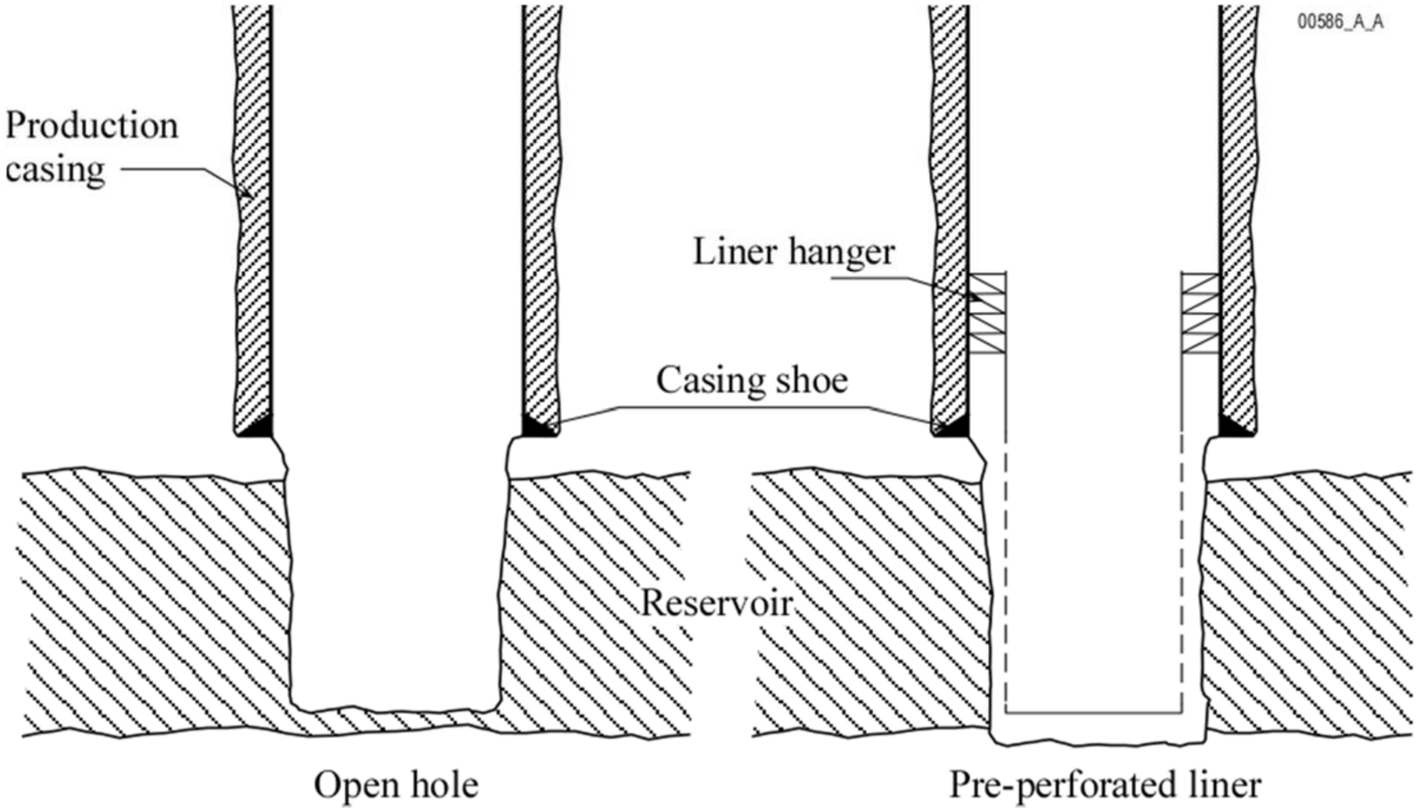
- Borehole wall stability
- Selectivity of fluid or pay zone(s)
  (including selectivity of the zone to be treated, if any, and treatment efficiency)
- Minimal restrictions along the flow path, so well flow potential optimization
- Well safety
- Flow adjustment
- Operations to be performed at a later date (measurement, maintenance, etc.) without having to resort to workover
- Easy workover when necessary

Configuration of the reservoir-wellbore interface

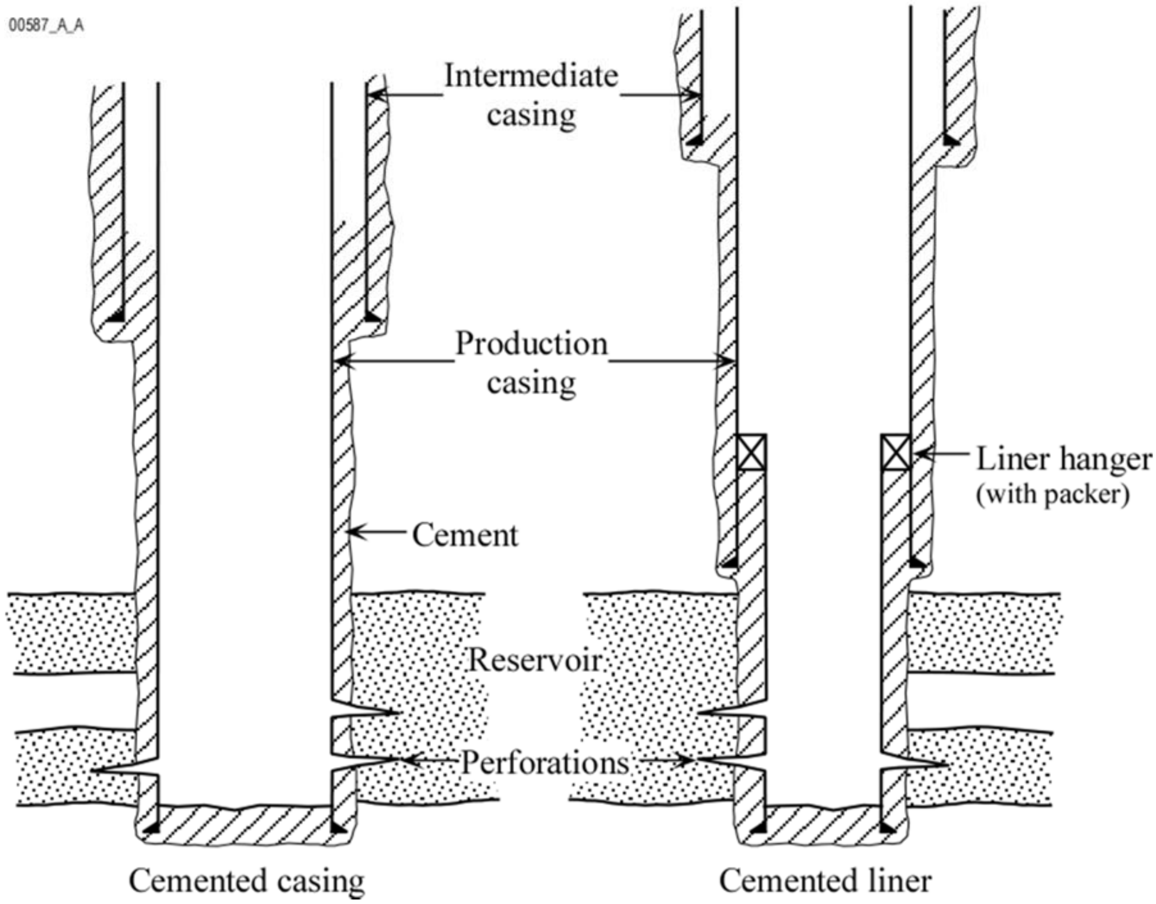
Configuration of the reservoir-wellbore interface

- **Choice between:**
  - Open hole*
  - Cased hole*
- **Also take into account (if the problem arises):**
  - The perforation method
  - The sand control method
  - The stimulation method
  - "Conventional" drain (vertical or slanted) or horizontal drain

Open hole completion



Cased hole completion

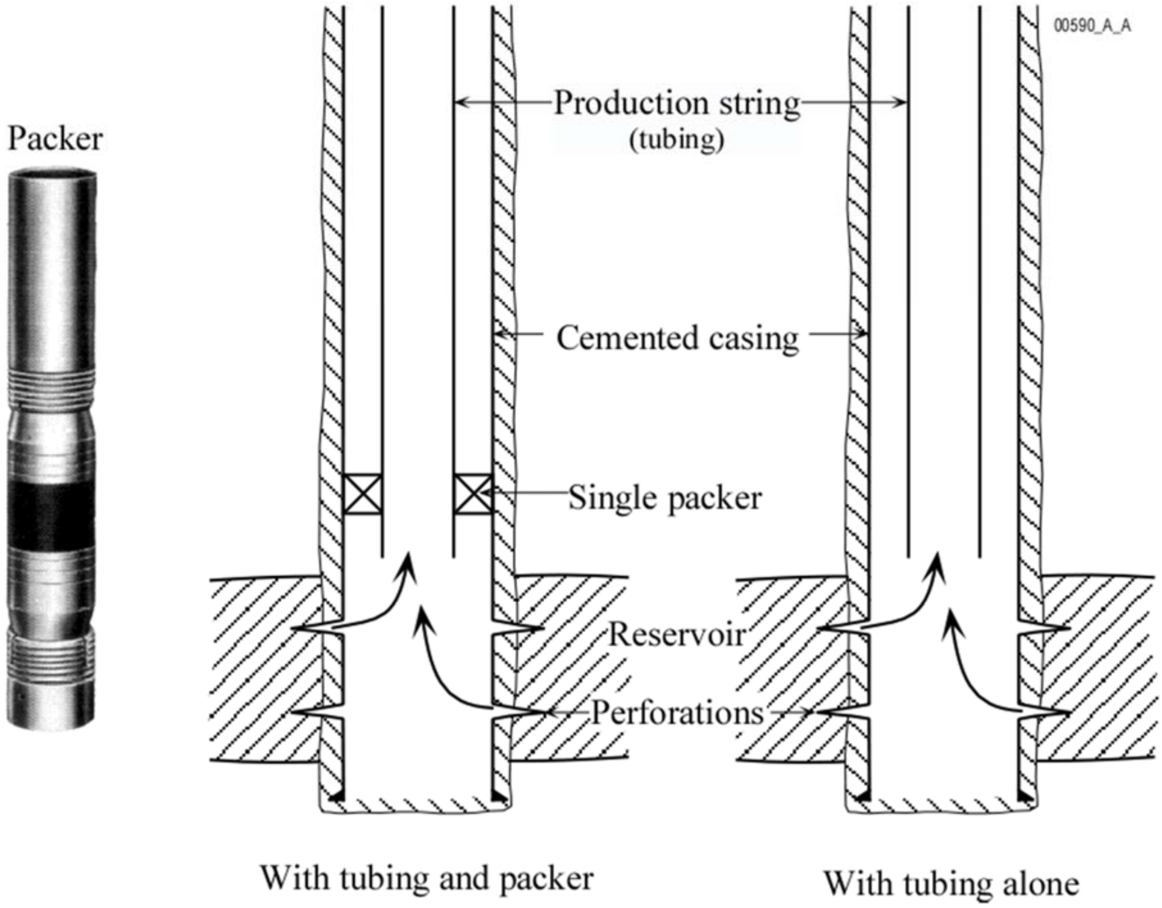


Configuration of the production string(s)

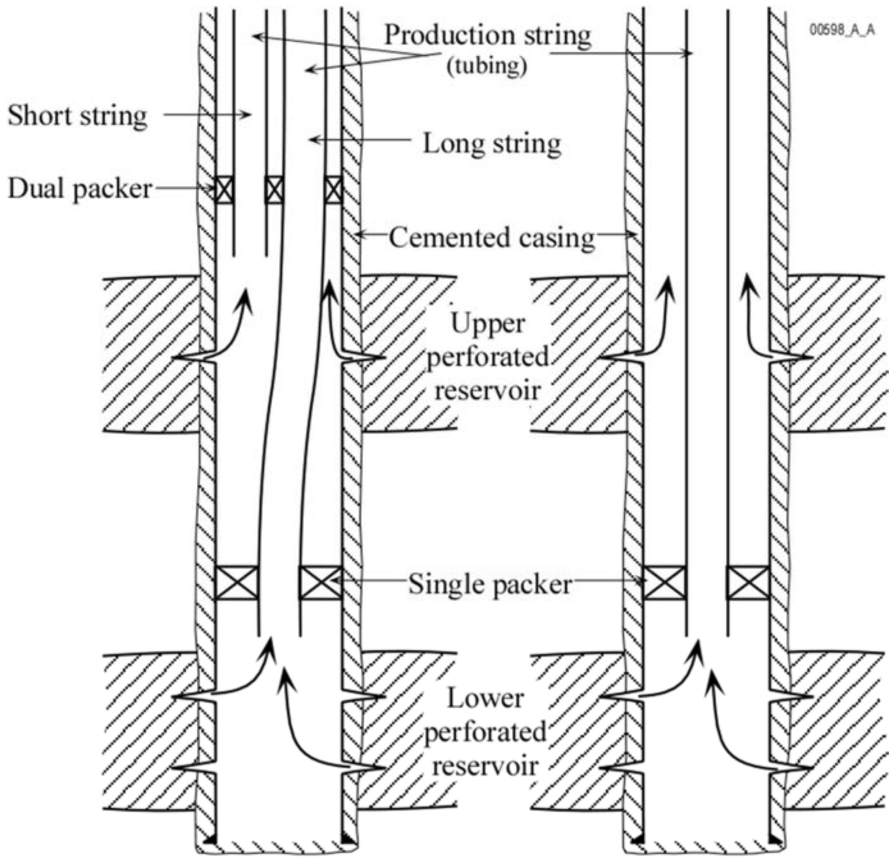
Configuration of the production string(s)

- **Conventional completion*:**
  - Single zone
  - Multi zones:
    - Parallel dual string
    - Tubing - annulus
    - Alternate selective
- **Tubingless completions*:**
  - Single zone
  - Multizones
- **Miniaturized completions**
- **Example of equipment for a naturally flowing well (single zone completion)***

Single zone completion

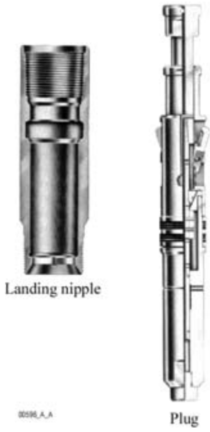


Multizone completion

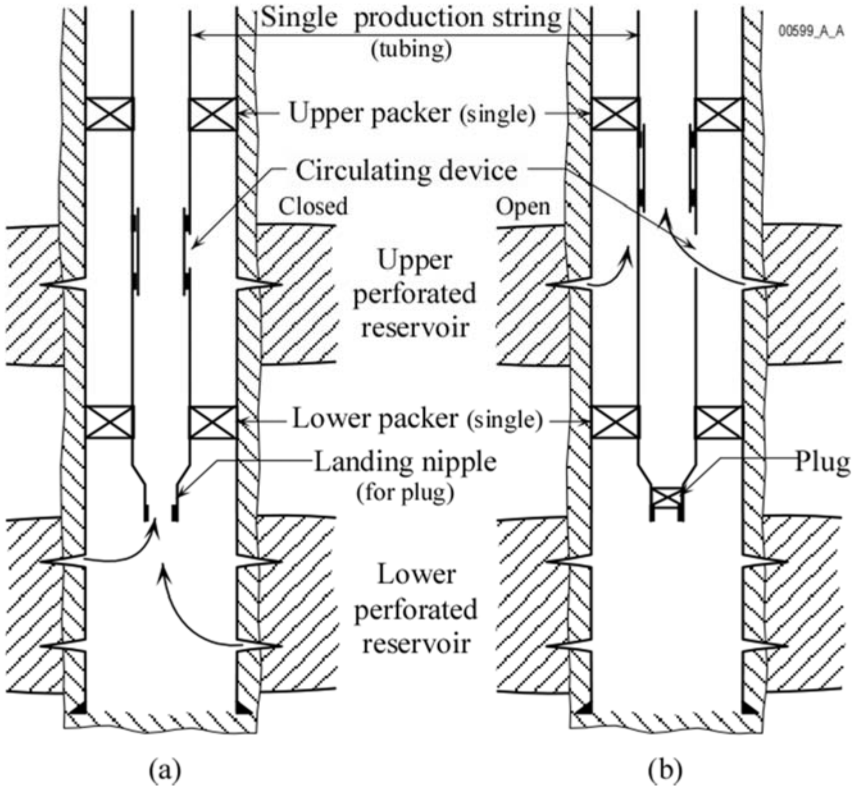


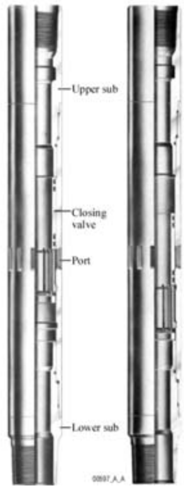
a: Parallel dual tubing strings **b: Tubing - annulus completion**

Multizone completion (cont.)

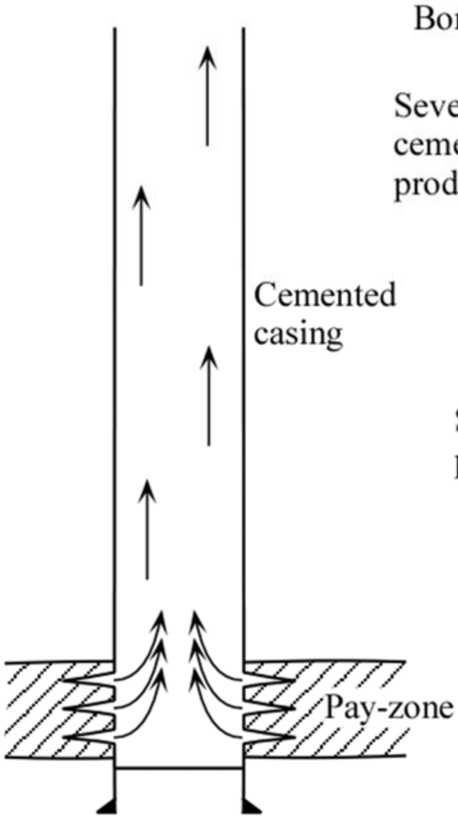


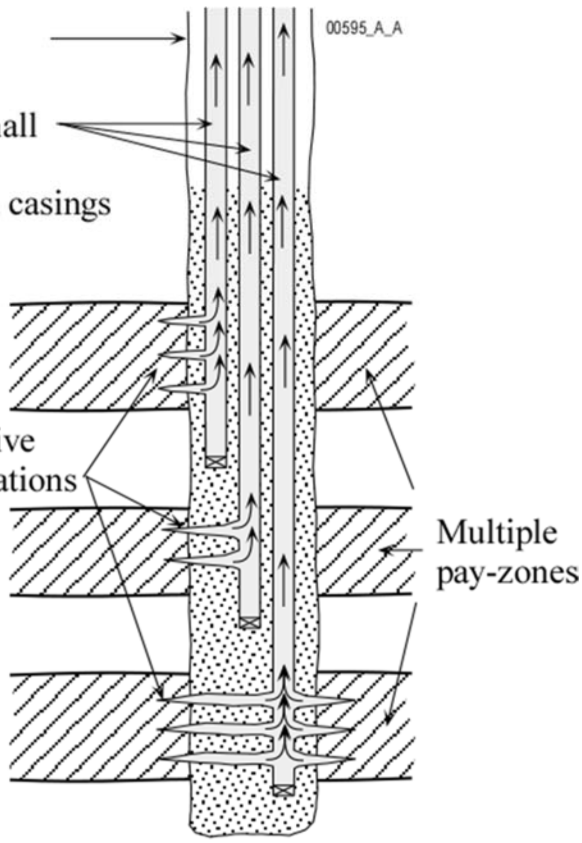
c: Alternate selective completion





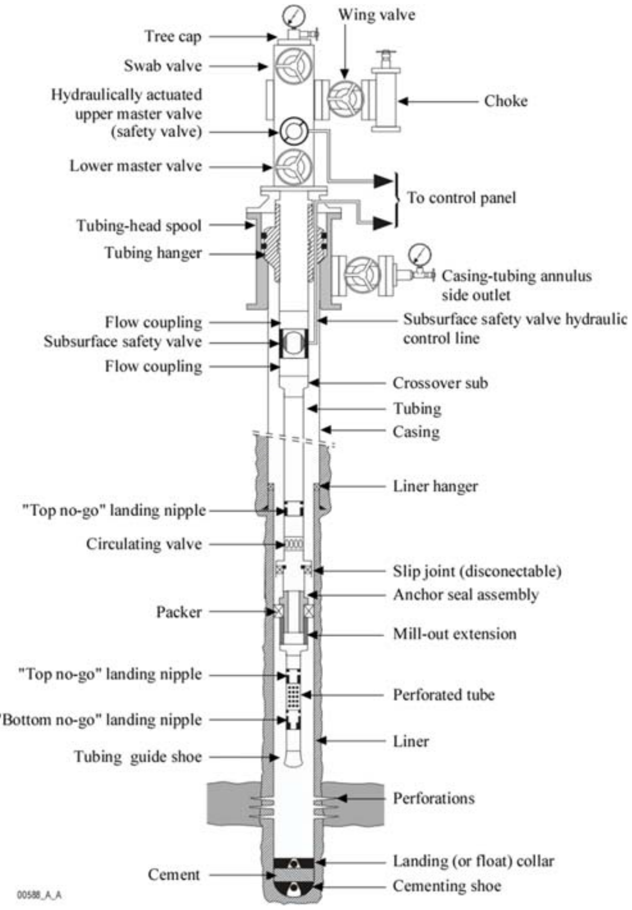
Tubingless completion





a: Single zone **b: Multi zones**

Synthesis: example of equipment for a naturally flowing well



Notes

Main phases in completion

Initial completion
(case of a cased hole configuration)

- Checking the cement job
- Remedial cementing (if needed)
- Re-establishing the pay zone-borehole communication
- Well testing
- Treating the pay zone:
  - Stimulation (acidizing, fracturing)
  - Sand control
- Equipment installation
- Putting the well on stream & Assessing performance
- Moving the rig

Operations to be performed at a later date

- Measurements
- Maintenance
- Workover
- Abandonment

Overall approach of the well flow potential

Contents

- Basic equations
- Productivity and flow efficiency
- Analysis of the different terms & Resulting conclusions
- Performance curves
- Extension of PI notion

Basic equations

Base equations

- **Well flow potential:**

$$Q = f\left(P_R, P_{BH}, \frac{h\,k}{\mu}, S\right)$$

- **If steady-state (or pseudo steady-state) flow:**
  - Case of an oil flow: $Q = PI\,(P_R - P_{BH})$
  - Case of a gas flow (empirical law): $Q = C\,(P_R^2 - P_{BH}^2)^n$ with $0.5 < n < 1$

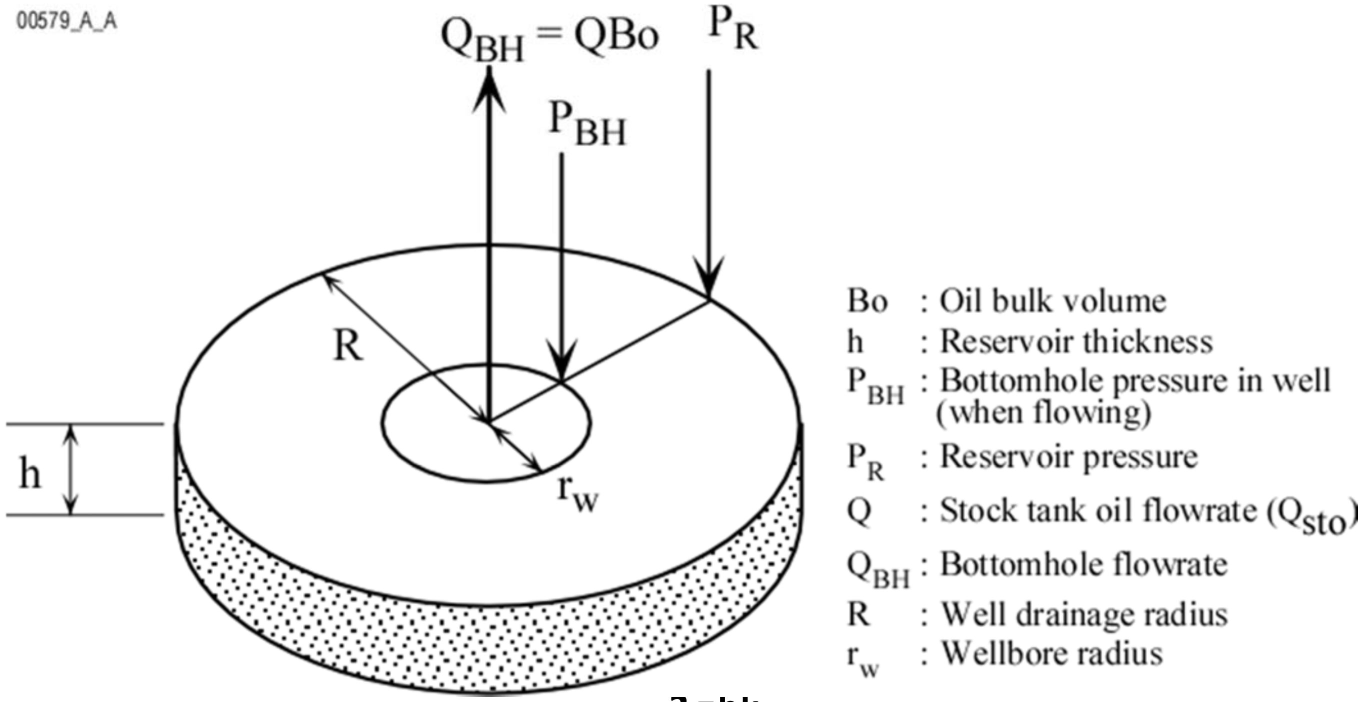
  with PI & C function of hk/μ and S

- **$P_{BH\ required}$ & $P_{BH\ available}$**
  - $P_{BH\ required} = P_{sep} + \Delta P_{fl} + P_{Hfl} + (\Delta P_{choke}) + \Delta P_{tbg} + P_{Htbg}$
  - $P_{BH\ available} = P_R - \Delta P_R$

    with $\Delta P_R = Q/PI$ if oil flowrate

Productivity index

(case of a liquid in steady-state and radial flow and for $P_{BH} > P_B$)



$$PI = \frac{2\pi hk}{B\mu \operatorname{Ln}\frac{R}{r_w}}$$

Productivity Index & Flow efficiency

(case of a liquid in steady-state and radial flow)

- Actual PI (PI) for a steady-state and radial flow: $PI = \frac{2\pi hk}{B\mu\left(\operatorname{Ln}\frac{R}{r_w} + S\right)}$
- Flow efficiency (Fe):

From a "Production" point of view:

$$Fe = \frac{PI}{PI_{th}} = \left[\frac{Q}{(P_R - P_{BH})}\right] \times \left[\frac{(P_R - P_{BH})_{th}}{Q_{th}}\right] = \left[\frac{(P_R - P_{BH})_{th}}{(P_R - P_{BH})}\right]_{Q=Cst} = \left[\frac{Q}{Q_{th}}\right]_{\Delta P=Cst}$$

From a "Reservoir engineering" point of view and for a steady-state and radial flow:

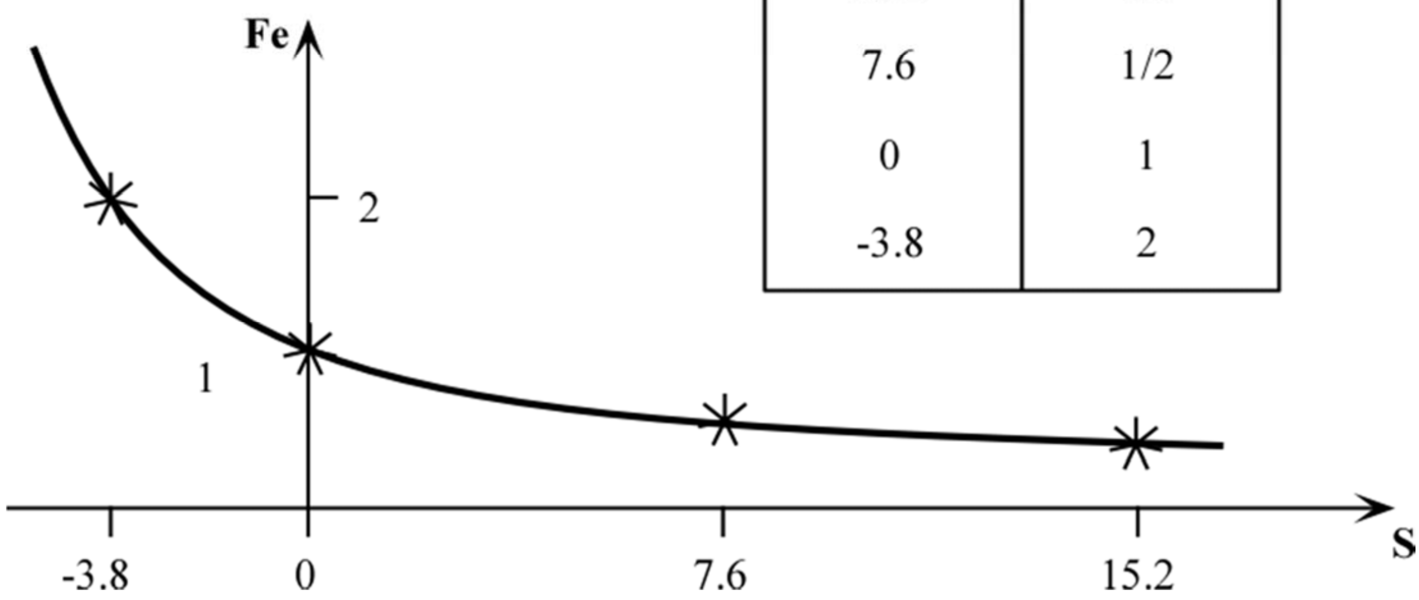
$$FE = \frac{PI}{PI_{th}} = \frac{2\pi hk}{B\mu\left(\operatorname{Ln}\frac{R}{r_w} + S\right)} \Big/ \frac{2\pi hk}{B\mu \operatorname{Ln}\frac{R}{r_w}} = \frac{\operatorname{Ln}\frac{R}{r_w}}{\operatorname{Ln}\frac{R}{r_w} + S}$$

Simplified form (for Ln R/r_w between 7 and 8): $FE = \frac{PI}{PI_{th}} \approx \frac{7}{7+S}$ to $\frac{8}{8+S}$

(usually it is considered that Ln $R/r_w \approx 7.6$)

Relationship between skin factor S and flow efficiency Fe

(case of a liquid in steady-state and radial flow & for Ln R/rw = 7.6)



S	Fe
15.2	1/3
7.6	1/2
0	1
-3.8	2

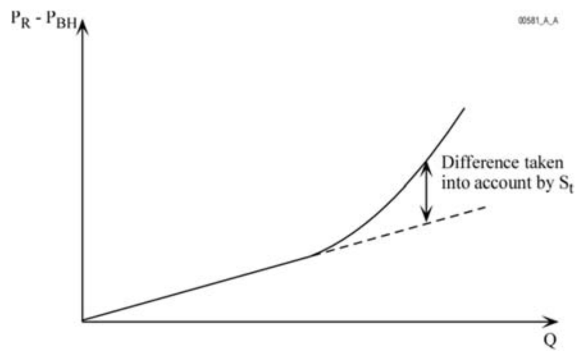
Parameter included in the global skin S

(steady-state and radial flow)

- S = 0 :
  - No damage
  - Well fully open (open hole) over the whole height of the pay zone
  - Well drilled perpendicular to the pay zone ("vertical")
  - No turbulence (laminar flow)
- S_d (damage):
  - $0 < S_d < +\infty$
  - $S_d = f(k_d/k_o, r_d)$
  - After treatment: $S_{d\ after\ treatment}$: + ∞ to 0 ⇒ + ∞ to 0 & perhaps - 2 (or even - 4)
- S_p (perforation):
  - $-1 < S_p < 0$ (or + 1)
  - $S_p = f(\text{penetration, phasing, SPF}, k_v/k_h)$
- S_{pp} (partial penetration):
  - $0 < S_{pp} < +7$ (or more)
  - $S_{pp} = f(h_p/h_u, \text{pattern}, k_v/k_h)$
- S_θ (deviation or inclination of a slanted well):
  - (- 3 to) $-1.5 < S_\theta < 0$
  - $S_\theta = f(\theta, k_v/k_h)$
- S_t* (turbulence)
- ...
- $S_{global\ (from\ well\ test)} = f(S_d, S_p, S_{pp}, S_\theta, ...)$

⇒ do not confuse S_{global} and S_d

$S_{global} > 0$ does not automatically imply $S_d > 0$



Turbulence effect

Practical formulas for PI & Fe (for Ln R/rw =7.6*)

(case of a liquid in steady-state and radial flow)

- $$PI_{(m^3/d/bar)} = \frac{h_{(m)} \times k_{(mD)}}{18.7 \times B_o \times \mu_{(cP)} \times (7.6 + S)}$$ with: 18.7 x 7.6 = 142

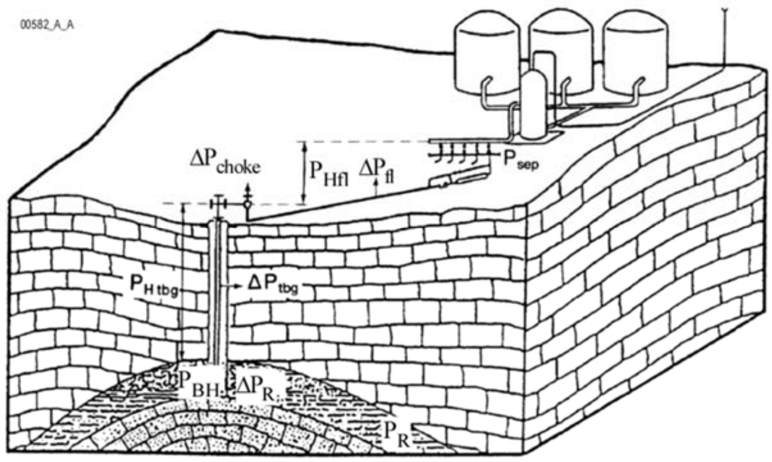
- $$PI_{(bbl/d/psi)} = \frac{h_{(ft)} \times k_{(mD)}}{141 \times B_o \times \mu_{(cP)} \times (7.6 + S)}$$ with: 141 x 7.6 = 1 072

- $$FE \approx \frac{7.6}{7.6 + S}$$

Note: 1 m^3/d/bar ≈ 0.43 bbl/d/psi & 1 bbl/d/psi ≈ 2.3 m^3/d/bar

*: Ln R/rw = 7.6 corresponds to a drainage radius of 200 m (656 ft) for 8" 1/2 drilling diameter

Fluid path from the reservoir to the process facilities



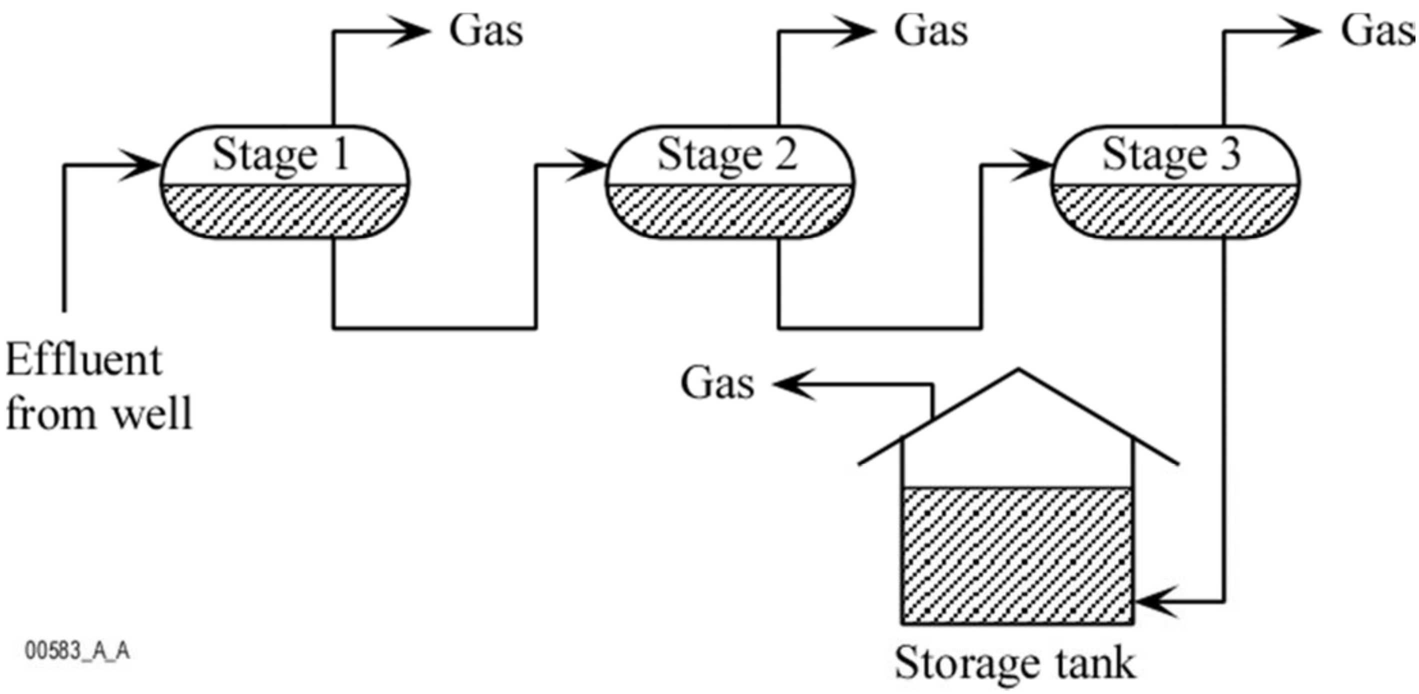
P_R	=	Reservoir pressure
ΔP_R	=	Pressure losses in the reservoir
P_{BH}	=	Bottomhole pressure
P_{Htbg}	=	Hydrostatic pressure in the tubing
ΔP_{tbg}	=	Pressure losses in the tubing
ΔP_{choke}	=	Pressure losses in the choke
P_{Hfl}	=	Hydrostatic pressure in the flowlines
ΔP_{fl}	=	Pressure losses in the flowlines
P_{sep}	=	Pressure at the surface treatment facility inlet

$P_{BH\ required} = P_{sep}^{*} + \Delta P_{fl} + P_{Hfl} + (\Delta P_{choke}) + \Delta P_{tbg} + P_{Htbg}^{*}$ **[outflow]**

$P_{BH\ available} = P_R - \Delta P_R$ **[inflow]**

with $\Delta P_R = Q/PI$ if oil flowrate

Multistage separation



Hydrostatic pressure

- **Hydrostatic pressure:**
  - $$P_{h(MPa)} = \frac{9.81 \times Z_{(m)} \times d_{(kg/l)}}{1\,000}$$
    or
  - $$P_{h(bar)} = \frac{9.81 \times Z_{(m)} \times d_{(kg/l)}}{100} \quad \text{ou} \quad \frac{Z_{(m)} \times d_{(kg/l)}}{10.2}$$
    or
  - $P_{h(psi)}$ = 0.052 x $MW_{(ppg)}$ x $Z_{(ft)}$
    or
    = 0.433 x SG x $Z_{(ft)}$

Note: 1 MPa = 10 bar

Note: 1 bar = 0.1 MPa

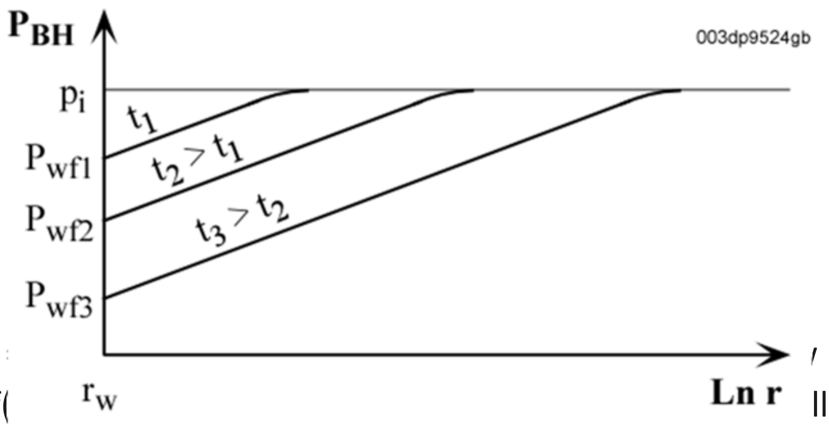
Conversion factors:

- 1 MPa = 145 psi — 1 psi = 6.895 10^{-3} MPa
- 1 m = 3.281 ft — 1 ft = 0.3048 m
- 1 kg/l = 8.345 ppg — 1 ppg = 0.1198 kg/l
- 1 kg/l = 62.43 lb/ft^3 — 1 lb/ft^3 = 0.01602 kg/l

Productivity index & flow efficiency

Infinite extent reservoir (or boundaries not yet reached)

- **"P_{BH} versus Ln r" diagram (excluding capacity and skin effects):**



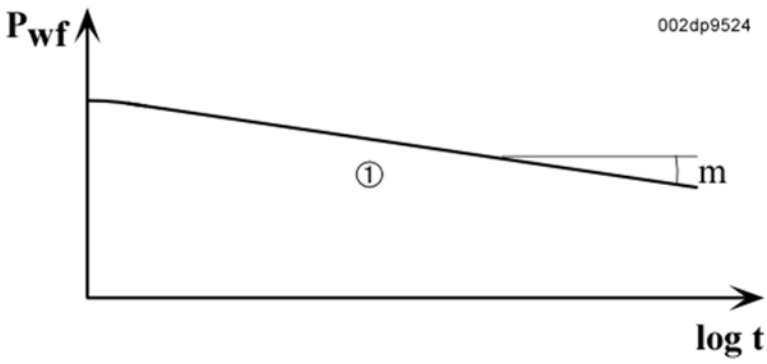
- $P_i = P_r$
- $P_{wf} = f($

P_{wf} decreasing when t increasing

- $P_i - P_{wf} = f(t) \Rightarrow$ transient flow

Infinite extent reservoir (or boundaries not yet reached) (cont)

- **"P_{wf} versus log t" diagram (excluding capacity and skin effects):**

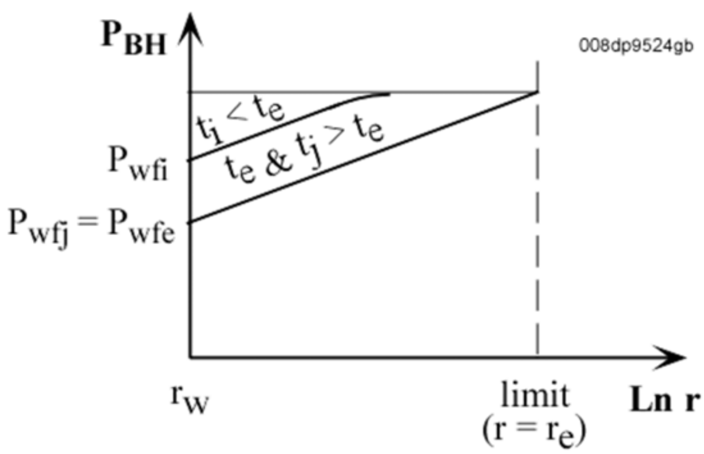


- For "t great enough": $P_{wf} = P_i - m \log t \Rightarrow$ transient flow

Case of a limited reservoir with constant pressure at the boundaries

In this case, it is considered that the pressure at the limit of the reservoir is maintained constant (perfect water drive or water flooding with perfect pressure maintenance for example)

- **"P_{BH} versus Ln r" diagram (excluding capacity and skin effects):**

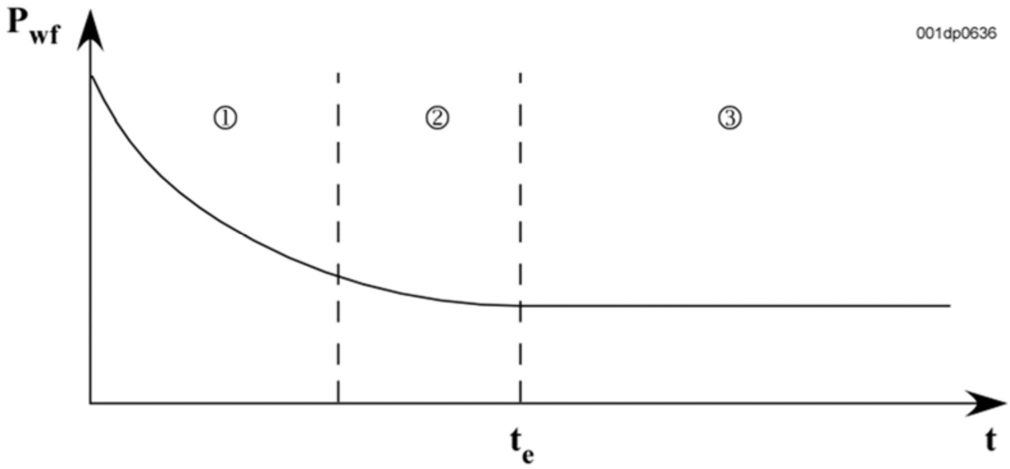


- For "$t > t_e$": $P_{wf} = cst$ & $P_i - P_{wf} = cst \Rightarrow$ steady state flow

(this type of flow is usually not reached during a well test when drilling, the well test duration being too short)

Case of a limited reservoir with constant pressure at the boundaries (cont.)

- **"P_{wf} versus t" diagram (excluding capacity and skin effects):**



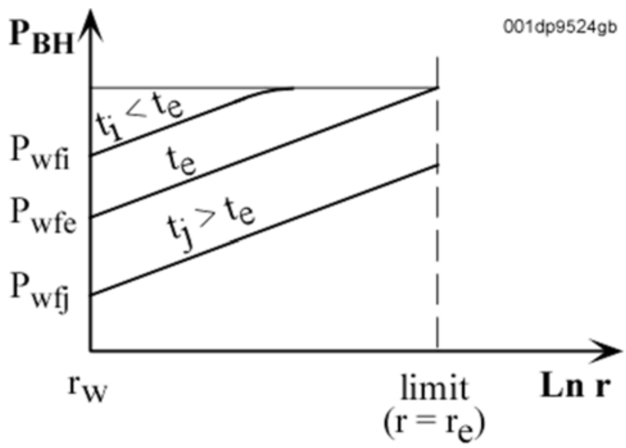
① Transient flow (reservoir acting as infinite): $P_{wf} = P_{1h} - m \log t$
②Transition zone
③ Steady state flow: $P_{wf} = cst$

- For "$t > t_e$": $P_{wf} = cst$ & $P_i - P_{wf} = cst$ ⇒ steady state flow

Case of a limited reservoir with no flow at the boundaries

In this case, the reservoir is considered as fully isolated from the outside by barriers allowing no communication (perfectly sealed reservoir)

- **"P_{BH} versus Ln r" diagram (excluding capacity and skin effects):**



For $t > t_e$, production is obtained only by decompression

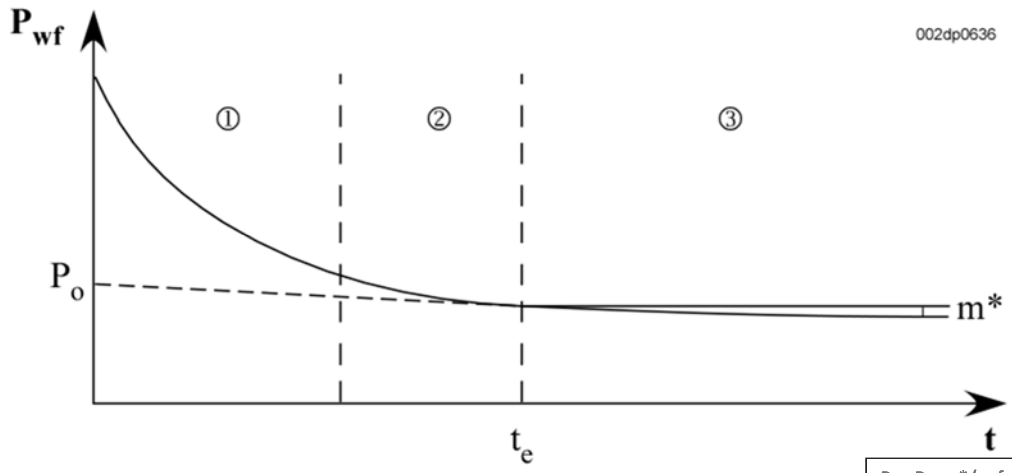
$\overline{P}$ = average pressure in the reservoir (once the well is shut back)

- For "$t > t_e$": $P_{wf} = f(t)$ but $\overline{P} - P_{wf} = cst$ ⇒ pseudo steady state flow

(this type of flow is usually not fully reached during a well test when drilling, the well test duration being too short)

Case of a limited reservoir with no flow at the boundaries (cont.)

▶ **"P_{wf} versus t" diagram (excluding capacity and skin effects):**



P_{1h}, P_o, m*/m function of:
- the shape of the limits
- the relative position of the well compared to the limits

① Transient flow (reservoir acting as infinite): $P_{wf} = P_{1h} - m \log t$

② Transition zone

③ Pseudo steady state flow: $P_{wf} = P_o - m^* t$

- For "$t > t_e$": $P_{wf} = f(t)$ but $\bar{P} - P_{wf} = cst \Rightarrow$ pseudo steady state flow

Theoretical formulas

	Transient flow	**Pseudo steady state flow**	**Steady state flow**
	Infinite reservoir (or boundaries not yet reached)	*No flow boundaries*	*Constant pressure boundaries*
"P_r"	$P_r = P_i = P^* = cst$	$"P_r" = \bar{P} = f(t)$	$P_r = P_i = cst$
P_{wf}	$P_{wf} = P_{1h} - m \log t$	$P_{wf} = P_0 - m * t$	$P_{wf} = P_0 = cst$
"P_r" - P_{wf}	$P_i - P_{wf} = f(t) = \alpha \log t + \beta$	$\bar{P} - P_{wf} = cst$	$P_i - P_{wf} = cst$
"PI"	$\cancel{\frac{q}{P_i - P_{wf}} = f(t) = \frac{4\pi k h}{B\mu\left(\ln\frac{Kt}{r_w^2} + 0.81 + 2S\right)}}$ ⇒ the flowrate can't be characterised by a PI	$PI = \frac{q}{\bar{P} - P_{wf}} = cst = \frac{2\pi k h}{B\mu\left(\ln\frac{r_e}{r_w} + S - 0.75\right)}$	$PI = \frac{q}{P_i - P_{wf}} = cst = \frac{2\pi k h}{B\mu\left(\ln\frac{r_e}{r_w} + S\right)}$
"J"	$\cancel{\frac{\ln\frac{Kt}{r_w^2} + 0.81}{\ln\frac{Kt}{r_w^2} + 0.81 + 2S} \text{ with } K = \frac{k}{\Phi\mu c_t}}$	$J = \frac{\ln\frac{r_e}{r_w} - 0.75}{\ln\frac{r_e}{r_w} + S - 0.75}$	$J = \frac{\ln\frac{r_e}{r_w}}{\ln\frac{r_e}{r_w} + S}$
S		$S = \left(\frac{1-J}{J}\right)\left(\ln\frac{r_e}{r_w} - 0.75\right)$	$S = \left(\frac{1-J}{J}\right)\ln\frac{r_e}{r_w}$

- With **P*** extrapolate on the Horner plot for $(t_p + \Delta t)/\Delta t = 1$
- With $\bar{P}$ worked out from **P*** with an suitable method, for example M.B.H. method (Mathew – Brons – Hazebrock)
- Furthermore: $\Delta P_{skin} = \frac{q B \mu}{2\pi k h} S$

Practical formulas for:

- Practical units defined in the table next page
- $\ln(R/r_w) = 7.6$ i.e. $\log(R/r_w) = 3.3$ or $R = 200$ m if r_w = 0.1 m

	Transient flow	Pseudo steady state flow	Steady state flow
	Infinite reservoir (or boundaries not yet reached)	*No flow boundaries*	*Constant pressure boundaries*
PI practical	$\cancel{\text{"PI"} = \dfrac{k\,h}{21.5\,B\,\mu\left(\log\left[\dfrac{8\times10^{-4}\,k\,t}{\Phi\,\mu\,c_t\,r_w^2}\right]+0.87S\right)}}$ ⇒ the flowrate can't be characterised by a PI	$PI = \dfrac{k\,h}{B\,\mu\,(128+18.7S)}$	$PI = \dfrac{k\,h}{B\,\mu\,(142+18.7S)}$
J practical	$\cancel{J = \dfrac{\log\left[\dfrac{8\times10^{-4}\,k\,t}{\Phi\,\mu\,c_t\,r_w^2}\right]}{\log\left[\dfrac{8\times10^{-4}\,k\,t}{\Phi\,\mu\,c_t\,r_w^2}\right]+0.87S}}$	$J = \dfrac{6.85}{6.85+S}$	$J = \dfrac{7.6}{7.6+S}$
S practical		$S = 6.85\left(\dfrac{1-J}{J}\right)$	$S = 7.6\left(\dfrac{1-J}{J}\right)$

Furthermore: $\Delta P_{\text{skin practical}} = 18.7\,\dfrac{q\,B\,\mu}{k\,h}\,S$

Practical units

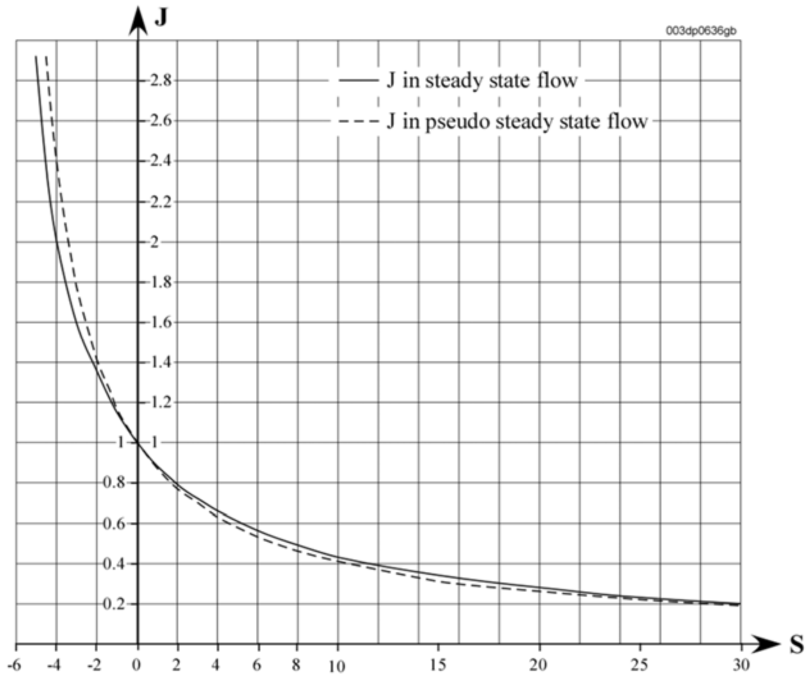
Parameters	Practical French units	Value in SI units
A (area)	m^2	1 m^2
c (compressibility)	bar^{-1}	10^{-5} Pa^{-1}
C (capacity)	m^3/bar	10^{-5} $m^3.Pa^{-1}$
h, r, l (height, radius, length)	m	1 m
k (permeability)	mD	0.987 x 10^{-15} m^2
K (diffusivity)	mD.bar/cP	0.987 x 10^{-7} x $m^2.s^{-1}$
m (slope of a straight line)	bar/cycle $\log_{10}$	10^5 Pa/cycle $\log_{10}$ (or 2.3 x 10^5 Pa/cycle ln)
P (pressure)	bar	10^5 Pa
q (flowrate)	m^3/j	(1 / 86,400) $m^3.s^{-1}$
t (time)	h	3600 s
T (temperature)	°K	1°K
μ (viscosity)	cP	10^{-3} Pa.s (*)
Ø (porosity)	fraction	fraction

(*) 1 Pa.s = 1 Pl (Poiseuille)

Curves "Flow efficiency versus skin" (for Ln R/r_w = 7.6)

S	- 5	- 4	- 3	- 2	- 1	0	1	2	3	4	6	8	10	15	20	25	30
J_{st}	2.92	2.11	1.65	1.36	1.15	1	0.88	0.79	0.72	0.66	0.56	0.49	0.43	0.34	0.28	0.23	0.20
J_{pst}	3.7	2.4	1.78	1.41	1.17	1	0.87	0.77	0.70	0.63	0.53	0.46	0.41	0.31	0.26	0.22	0.19

with J_{st} = Flow efficiency in steady state flow
J_{pst} = Flow efficiency in pseudo steady state flow

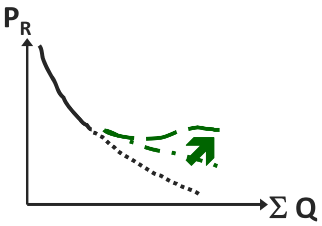


Analysis of the different terms & Resulting conclusions

Analysis of the different terms & Resulting conclusion

SECONDARY RECOVERY:

- *PRESSURE MAINTENANCE:*
  - To (avoid or) limit problems
  (- Help for flowing)
- *SWEEPING EFFECT*



$$Q \nearrow = f\left(P_R,\ P_{BH} \searrow,\ \overbrace{\frac{hk}{\mu},\ S}^{PI,\ C\ \nearrow}\right)$$

- ΔP_{FL}, ΔP_{tbg} optimisation
- P_{sep} optimisation
- If oil well, ↘ P_{Htbg}: ARTIFICIAL LIFT
  - ↘ "Z": *PUMPING*
  - ↘ "ρ": *GAS LIFT*
- If gas well, compressor at the surface (if necessary)

PI, C ↗: **STIMULATION**

- $S_d > 0$: matrix treatment
  - *ACIDIZING*
  - *Solvents*
- $k_{natural}$ small or very small:
  - *HYDRAULIC FRAC*
  - *(Horizontal drain)*

- μ high or very high:
  - *THERMAL METHODS*
  (classified as "SECONDARY or even TERTIARY RECOVERY)

Note:

For an oil well (with $P_{BH} > P_B$):
$Q = PI\ (P_R - P_{BH})$

For a gas well (empirical law):
$Q = C\left(P_R^2 - P_{BH}^2\right)^n$ with $0.5 < n < 1$

with PI & C function of hk/μ & S

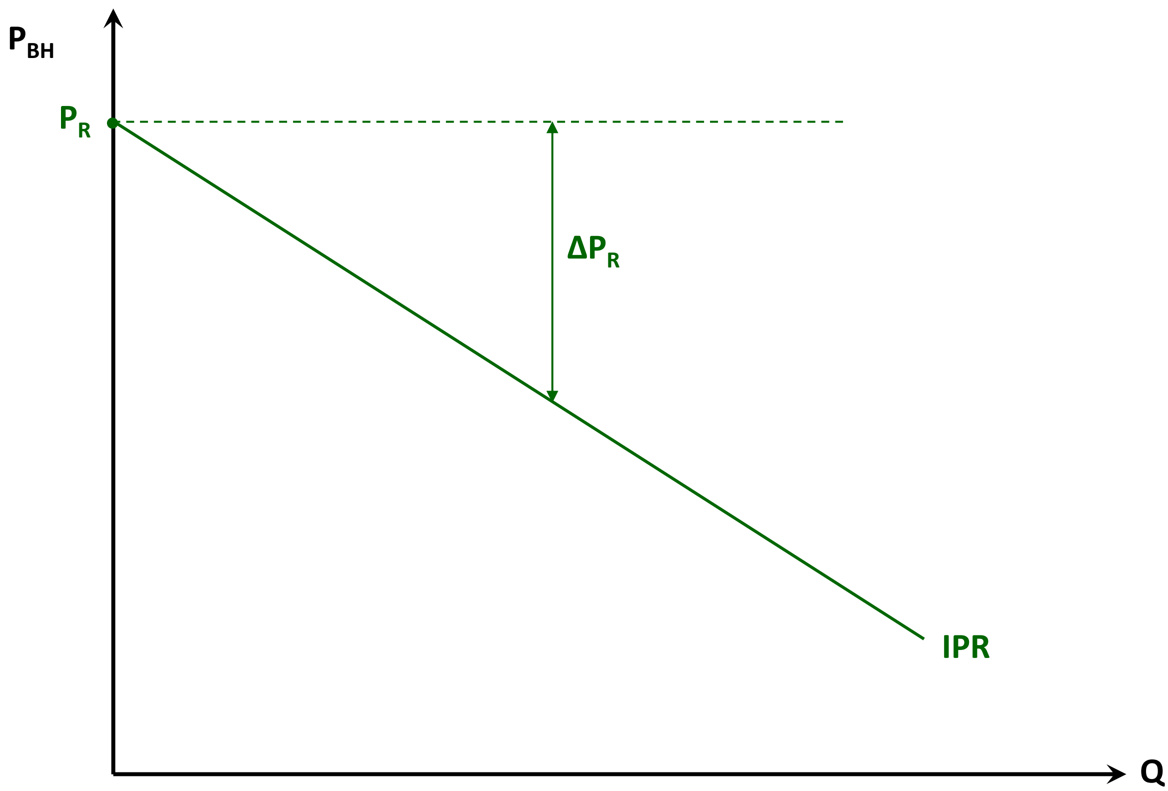
Analysis of the different terms & Resulting conclusion (cont.)

- **Decreasing P_{BH}:**
  - Case of an oil well:
    - Moderate P_{sep}
    - Small ΔP_{tbg}
    - Decreasing P_H: pumping, gas-lift $\Rightarrow$ Artificial lift
  - Case of a gas well:
    - Small ΔP_{tbg}
    - Recompression on surface
- **Increasing productivity:**
    - Acidizing, fracturing… $\Rightarrow$ Stimulation
- **Slowing down the decline of P_R:**
    - Water (or gas) injection $\Rightarrow$ Secondary recovery

Performance curves

IPR curve in monophasic flow

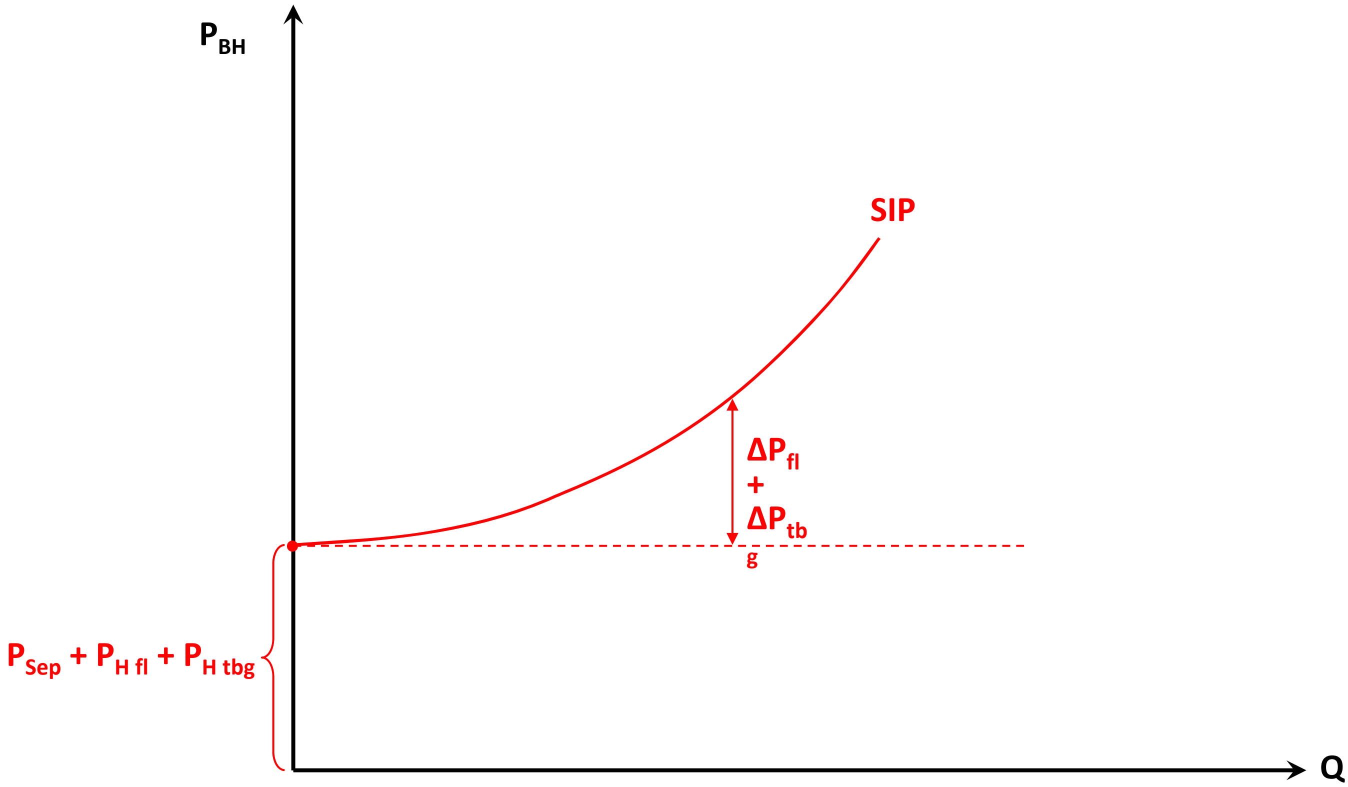
(Inflow Performance Response curve)



IPR: Inflow performance response curve

SIP curve in monophasic flow

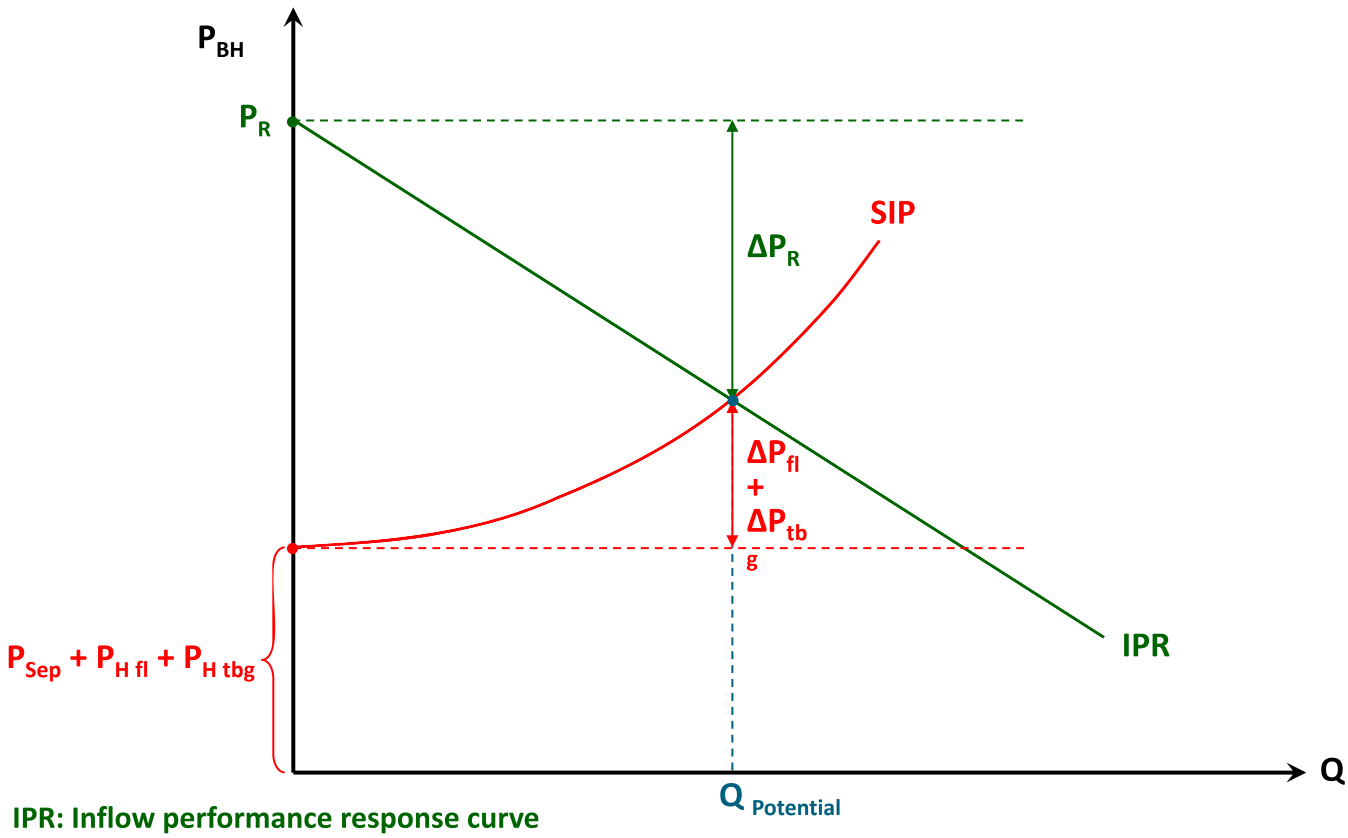
(System Intake Performance curve: outflow)



SIP: System intake performance curve (also called "VLP": Vertical lift performance)

IPR & SIP curves in monophasic flow

(Inflow & outflow)

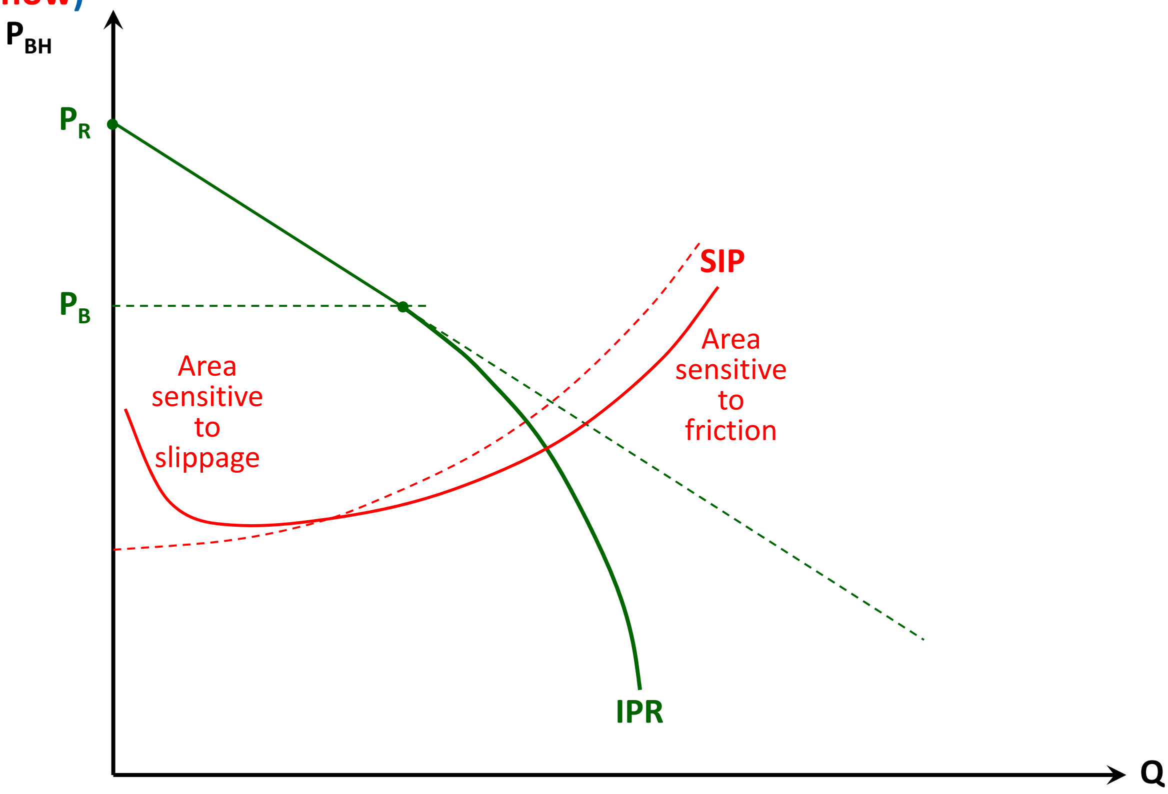


IPR: Inflow performance response curve

SIP: System intake performance curve (also called "VLP": Vertical lift performance)

IPR & SIP curves in polyphasic flow

(Inflow & outflow)



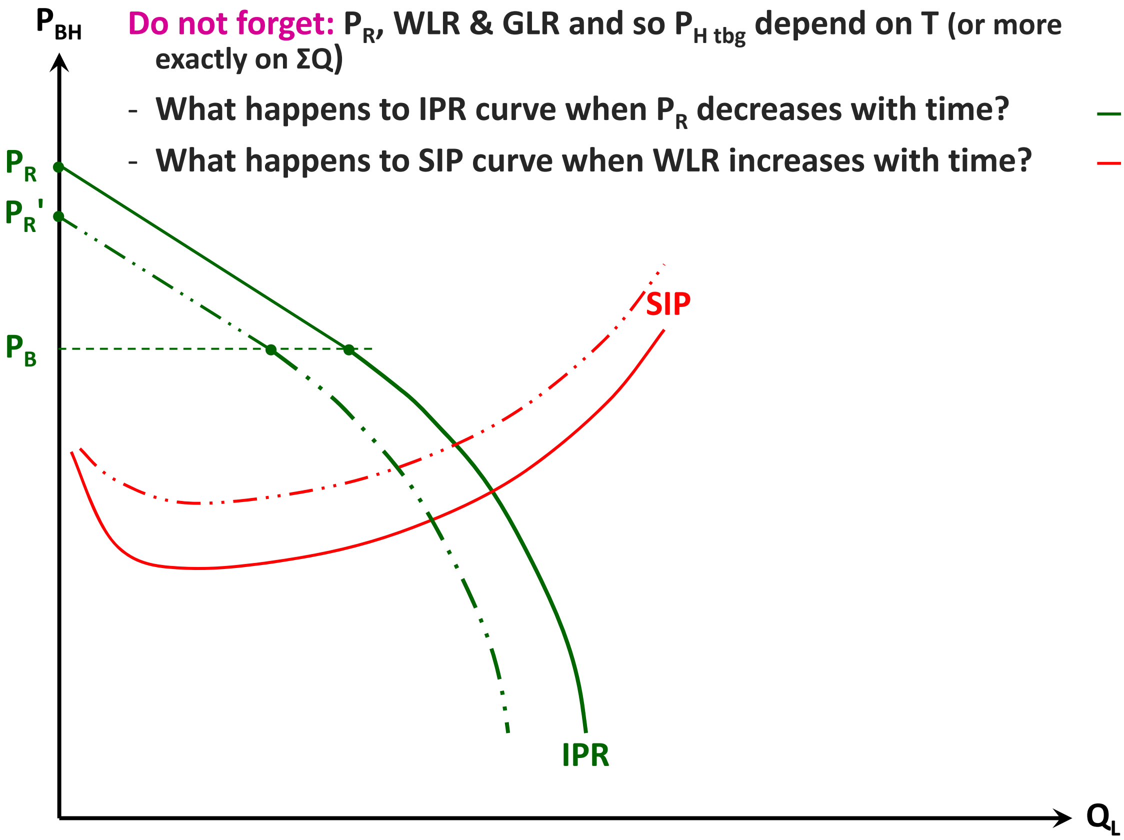
IPR: Inflow performance response curve

SIP: System intake performance curve (also called "VLP": Vertical lift performance)

Effect of the time on IPR & SIP curves

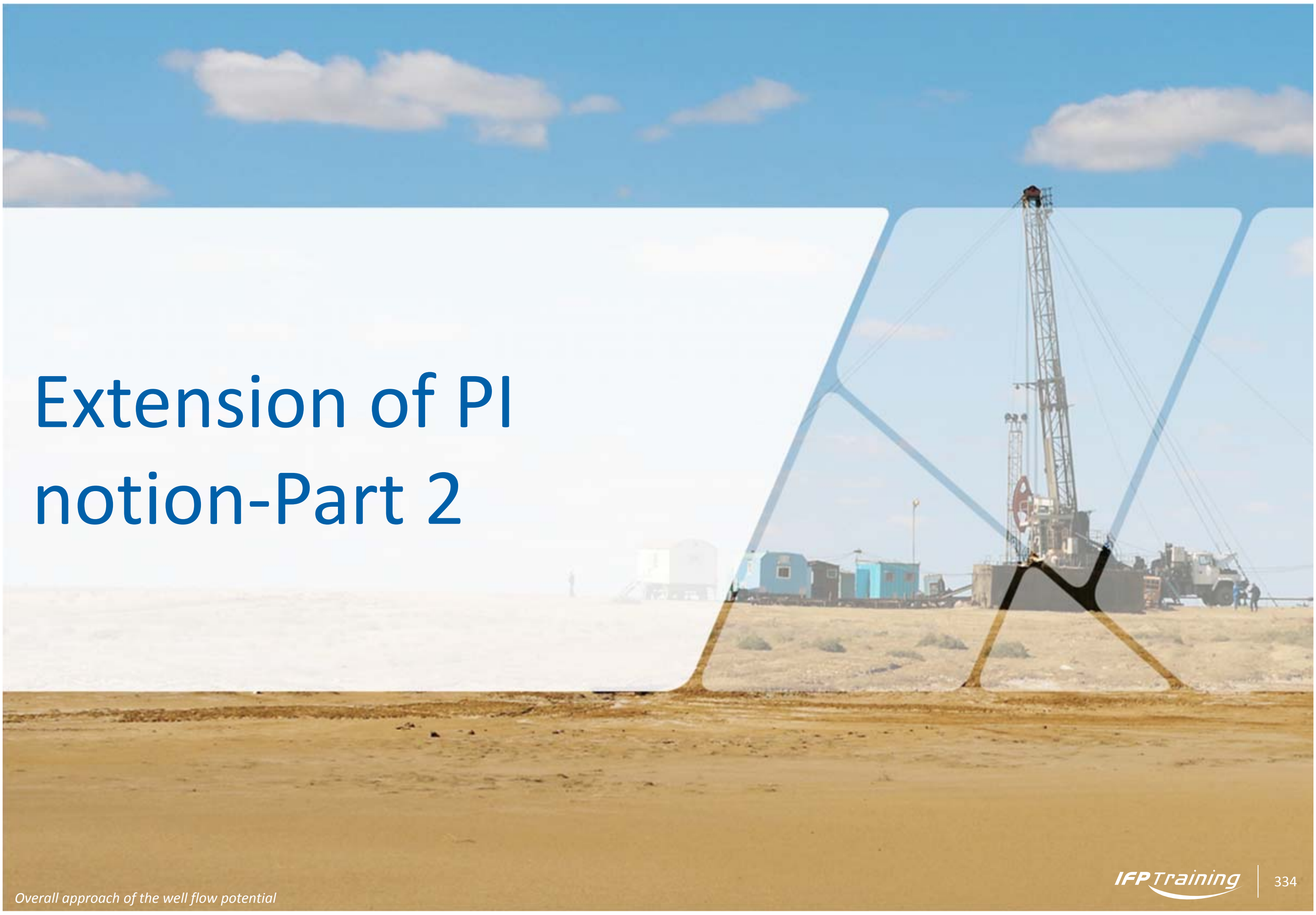
Do not forget: P_R, WLR & GLR and so $P_{H\ tbg}$ depend on T (or more exactly on ΣQ)

- What happens to IPR curve when P_R decreases with time?
- What happens to SIP curve when WLR increases with time?



IPR: Inflow performance response curve

SIP: System intake performance curve (also called "VLP": Vertical lift performance)



Extension of PI notion-Part 2

Main assumptions

IPR (Inflow Performance Relationship) according to J.V. VOGEL Solution-gas drive reservoir

- Reservoir shut-in pressure = Bubble pressure
- Circular reservoir, uniform and isotropic porous medium
- No skin effect
- Oil and gas at the same pressure and with constant properties (viscosity)
- No flow of water

Empirical equation

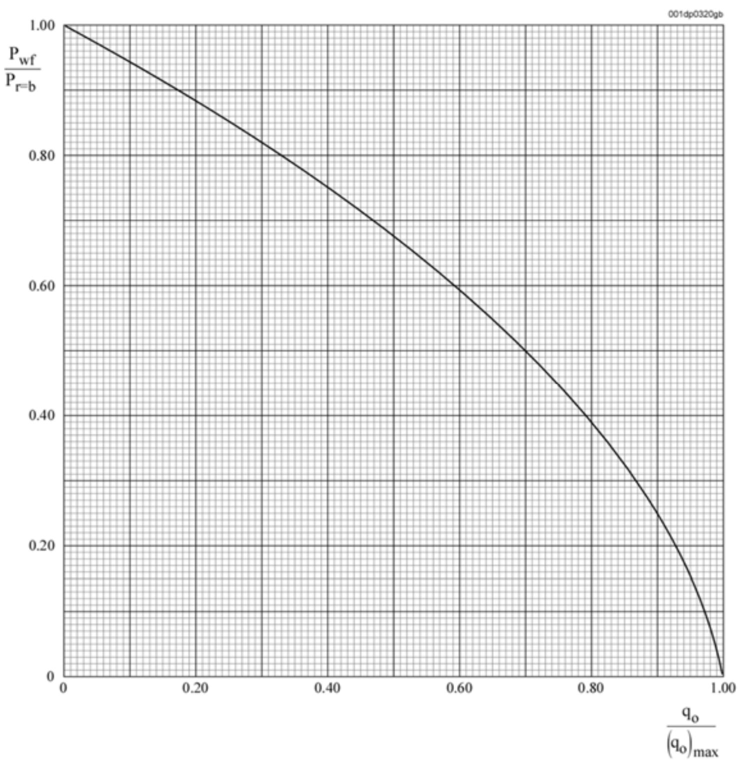
- **Empirical equation:**

$$\frac{q_o}{\left(q_o\right)_{max}} = 1 - 0.2\frac{P_{wf}}{P_{r=b}} - 0.8\left(\frac{P_{wf}}{P_{r=b}}\right)^2$$

- **Comments, limits:**
  - The deviation between the anticipated flowrate and actual flowrate may be significant if:
    - Oil is very viscous
    - Reservoir shut-in pressure is greater than bubble pressure
    - There is some skin effect
  - Otherwise, deviation is smaller than 20 % and even 10 %
  - Approach still valid for the liquid flowrate (oil + water) if BSW < 10 %
  - Regularly, make again a match point

IPR Curve

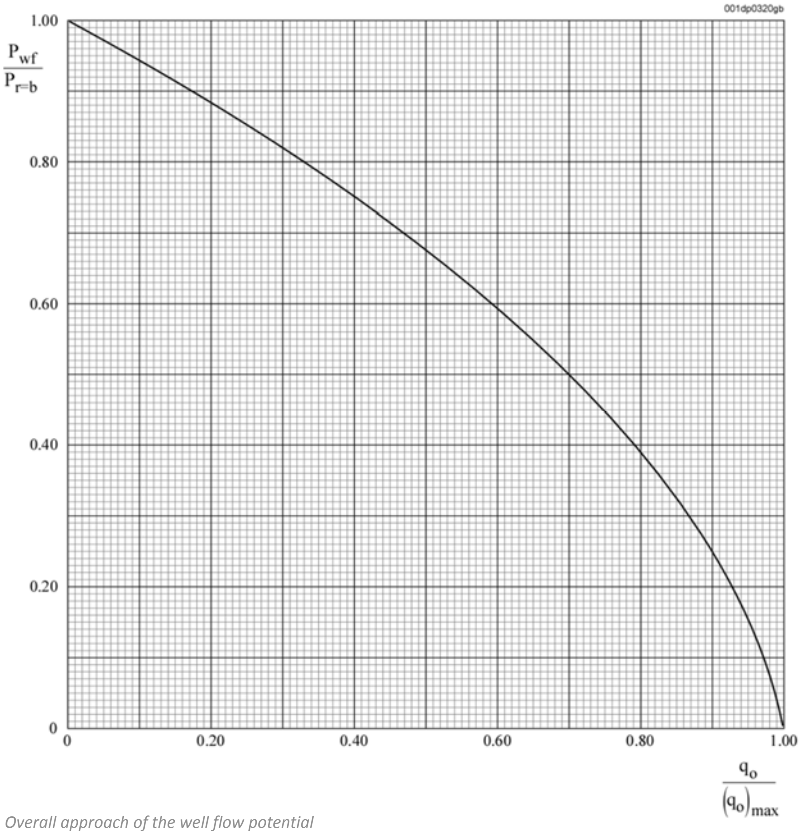
- **IPR curve: Curve $\frac{P_{wf}}{P_{r=b}}$ versus $\frac{q_o}{(q_o)_{max}}$**



- **How to use the IPR curve:**
  - To use this method, a match point must be known
  - Using the curve (or the equation), calculate $(q_o)_{max}$
  - From there, it is possible to calculate the flowrate for any bottomhole pressure

IPR Curve: example

- IPR curve: Curve $\dfrac{P_{wf}}{P_{r=b}}$ versus $\dfrac{q_o}{(q_o)_{max}}$



- **Example:**
  - A well produces 120 m³/d with a bottomhole pressure equal to 75 bar, reservoir pressure is 100 bar (with $P_r = P_{bubble}$ of oil)
  - What would the flowrate be for a bottomhole pressure equal to 25 bar ?

For $P_b < P_{wf} < P_r$ and for $P_{wf} < P_b < P_r$

Case where Pr > Pb according to D. PATTON and M. GOLAN

- **For $P_b < P_{wf} < P_r$:**
  - Monophasic flow, so:

    $q = PI\,(P_r - P_{wf})$
  - In particular, for $P_{wf} = P_b$:

    $q_b = PI\,(P_r - P_b)$ that is to say: $$q_b = q\,\frac{P_r - P_b}{P_r - P_{wf}}$$
- **For $P_{wf} < P_b < P_r$:**

  $q = q_b + q'$ with $$q_b = PI\left(P_r - P_b\right)$$

  So q' is defined from Vogel curve provided: $$q' = \left[q_{max} - q_b\right]\left[1 - 0.2\frac{P_{wf}}{P_b} - 0.8\left(\frac{P_{wf}}{P_b}\right)^2\right]$$

  - using P_b (and not P_r) in the ratio $\dfrac{P_{wf}}{P_b}$

  - using the ratio $$\frac{q - q_b}{q_{max} - q_b} = \frac{q'}{q_{max} - q_b}$$ instead of $\dfrac{q_o}{(q_o)_{max}}$

Synthesis

- If there is a match point for $P_{wf} > P_b$ and another for $P_{wf} < P_b$:
  - q can be calculated for any P_{wf}
- If there is only one match point and provided we consider there is continuity between the two cases:
  - *if the match point is for $P_{wf} > P_b$:*

$$q_{max} = q_b + \frac{pq_{max} - q_b}{1.8} \qquad \text{(a)}$$

with pq_{max} = pseudo maximum flowrate

= flowrate for P_{wf} = 0 and PI at $P_{wf} > P_b$

that is to say:

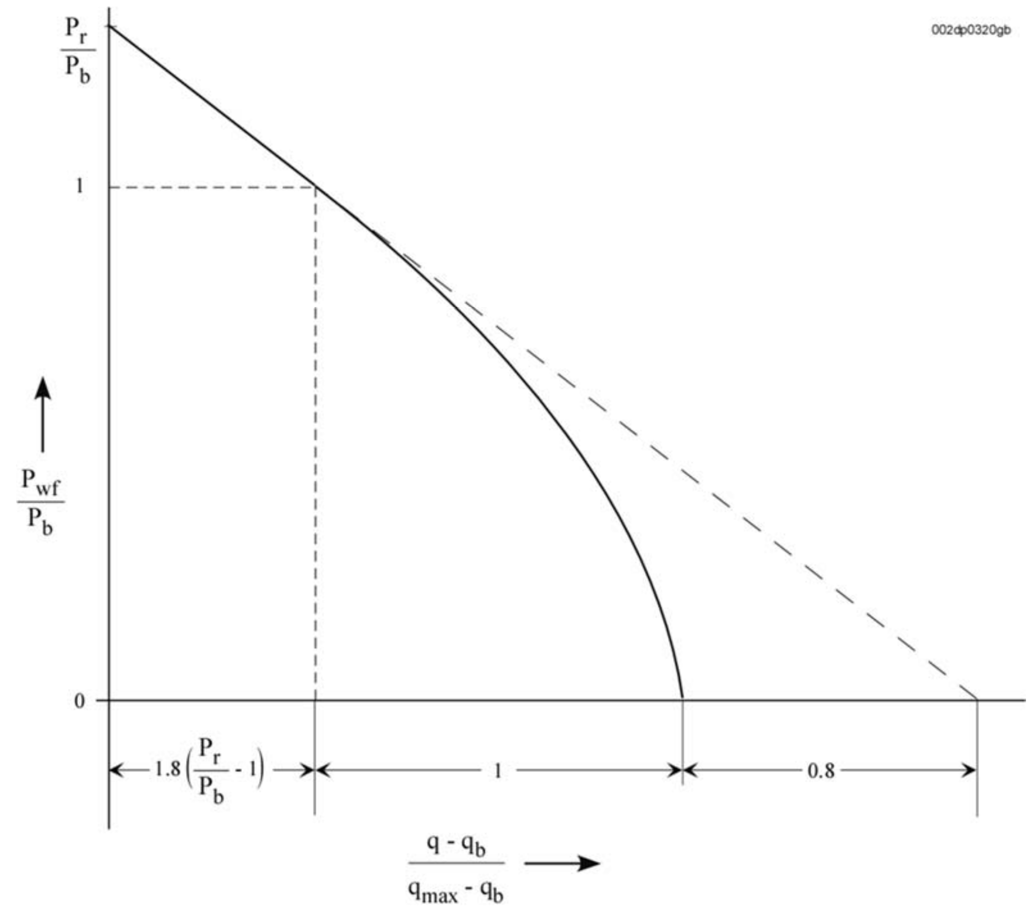
pq_{max} = PI x P_r or or $q_b \dfrac{P_r}{P_r - P_b}$ $\qquad q \dfrac{P_r}{P_r - P_{wf}}$

  - *If the match point is for $P_{wf} < P_b$:*

$$q_{max} - q_b = q \Big/ \left[1.8\frac{P_r}{P_b} - 0.8 - 0.2\frac{P_{wf}}{P_b} - 0.8\left(\frac{P_{wf}}{P_b}\right)^2\right] \qquad \text{(b)}$$

$$q_b = 1.8\left(\frac{P_r}{P_b} - 1\right)\left(q_{max} - q_b\right) \qquad \text{(c)}$$

Graphical representation



In practice

- If $P_{wf(m.p)} > P_b$

① $$\boxed{q_b} = q_{m.p} \frac{P_r - P_b}{P_r - P_{wf(m.p)}}$$

② $$pq_{max} = q_{m.p} \frac{P_r}{P_r - P_{wf(m.p)}}$$

③ $$q_{max} = q_b + \frac{pq_{max} - q_b}{1.8}$$ = ① + [②-①]/1.8 (a)

④ $\boxed{q_{max} - q_b}$ = ③ - ① = [②-①]/1.8

⑤ For $P_{wf} < P_b$:

For	Work out	Read on the chart	Work out
P_{wf}	$\frac{P_{wf}}{P_b}$	$R = \frac{q - q_b}{q_{max} - q_b}$	$q = \boxed{q_b} + R\boxed{(q_{max} - q_b)}$ = ① + [R x ④]

In practice (cont)

- If $P_{wf(m.p)} < P_b$

⑥ $$\boxed{q_{max} - q_b} = \frac{q_{m.p}}{1.8\frac{P_r}{P_b} - 0.8 - 0.2\frac{P_{wf(m.p)}}{P_b} - 0.8\left(\frac{P_{wf(m.p)}}{P_b}\right)^2}$$ (b)

⑦ $$\boxed{q_b} = 1.8\left(\frac{P_r}{P_b} - 1\right)(q_{max} - q_b)$$ (c)

⑧ For $P_{wf} < P_b$:

For	Work out	Read on the chart	Work out
P_{wf}	$\frac{P_{wf}}{P_b}$	$R = \frac{q - q_b}{q_{max} - q_b}$	$q = \boxed{q_b} + R\boxed{(q_{max} - q_b)}$ = ⑦ + [R x ⑥]

Reservoir-wellbore interface

(excluding "Wellbore treatments")

IFP Training

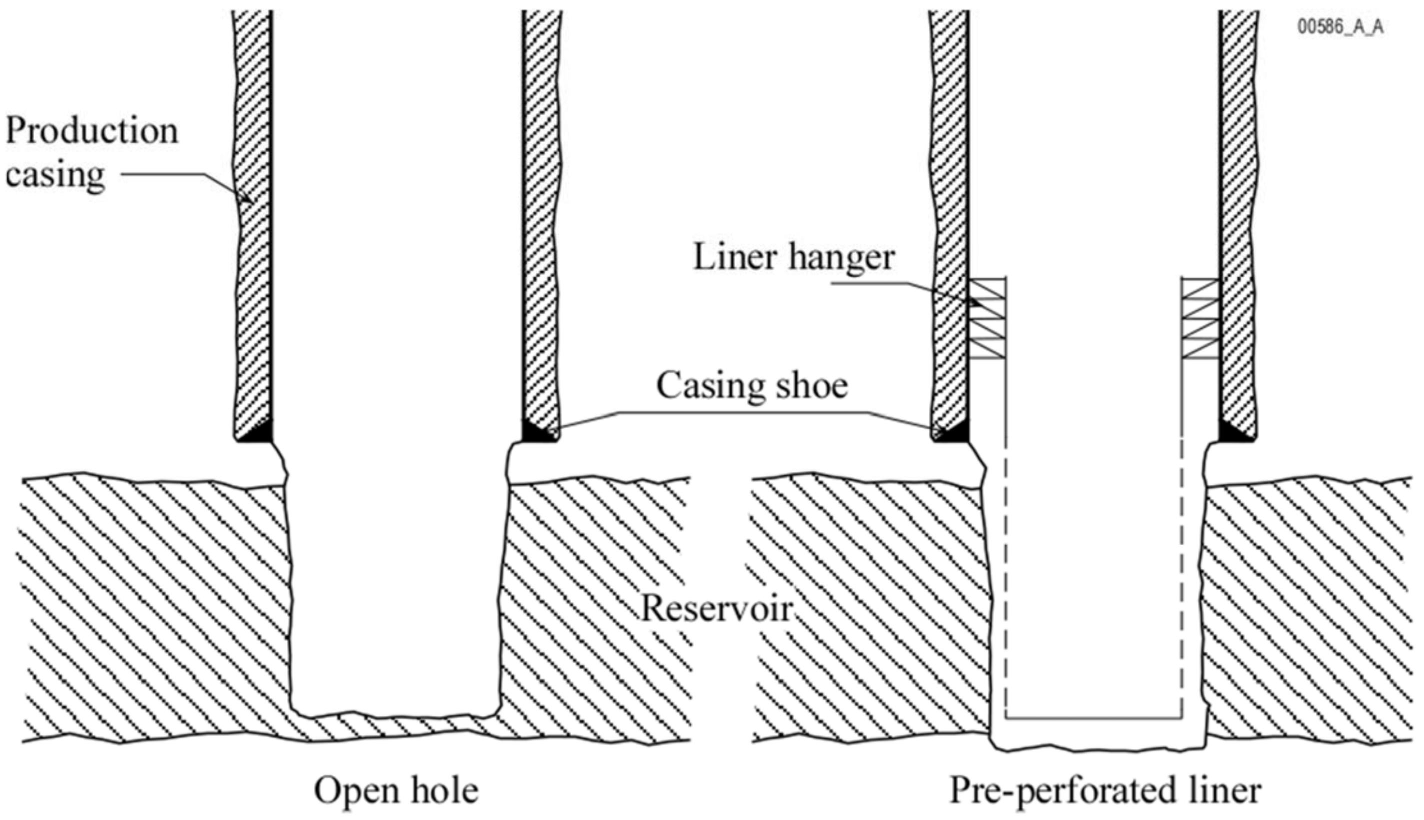
CONTENTS

Main configurations of the reservoir-wellbore interface
(for memory)

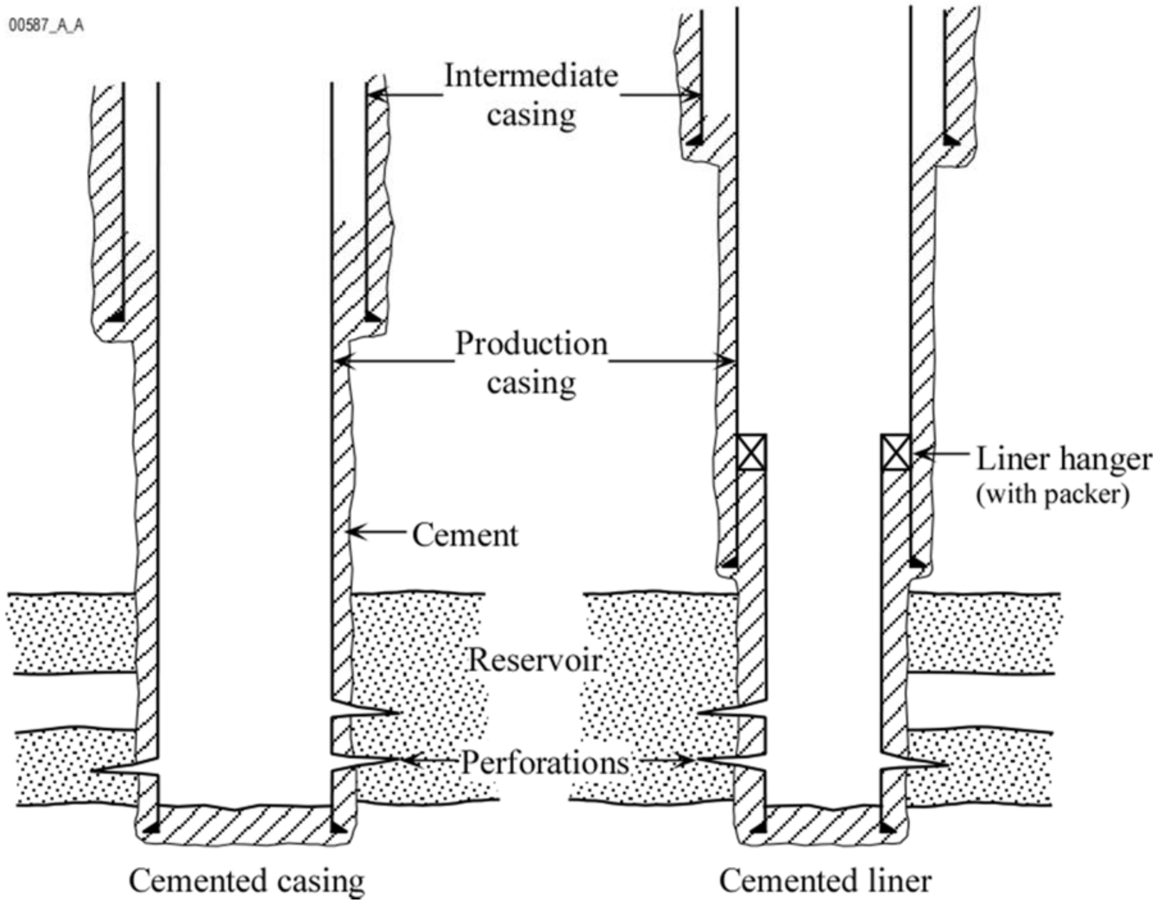
Main configurations of the reservoir-wellbore interface (for memory)

- **Basic requirements:**
  - Borehole wall stability
  - Selectivity of fluid or pay zone(s)
    (including selectivity of the zone to be treated, if any, and treatment efficiency)
  - Minimal restrictions along flow path, so well flow potential optimisation
- **Configuration of pay zone-borehole connection:**
  - Open hole completions*
  - Cased hole completions*

Open hole completion



Cased hole completion



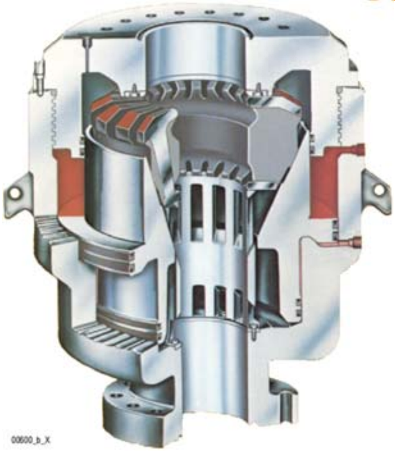
Drilling & casing the pay zone

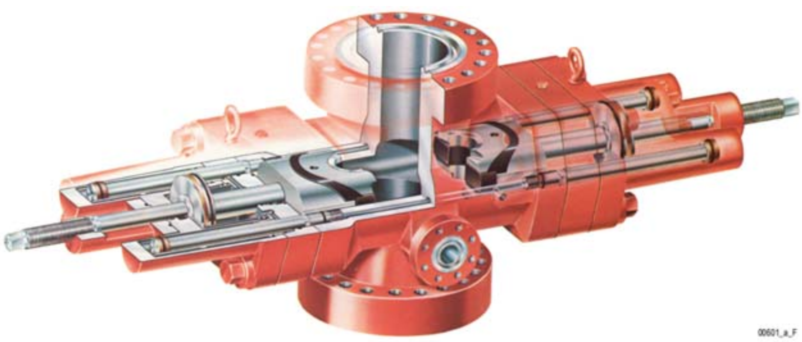
Well safety

- Density of the fluid in the well
- Safety equipment*
- Operating precautions

Safety equipment

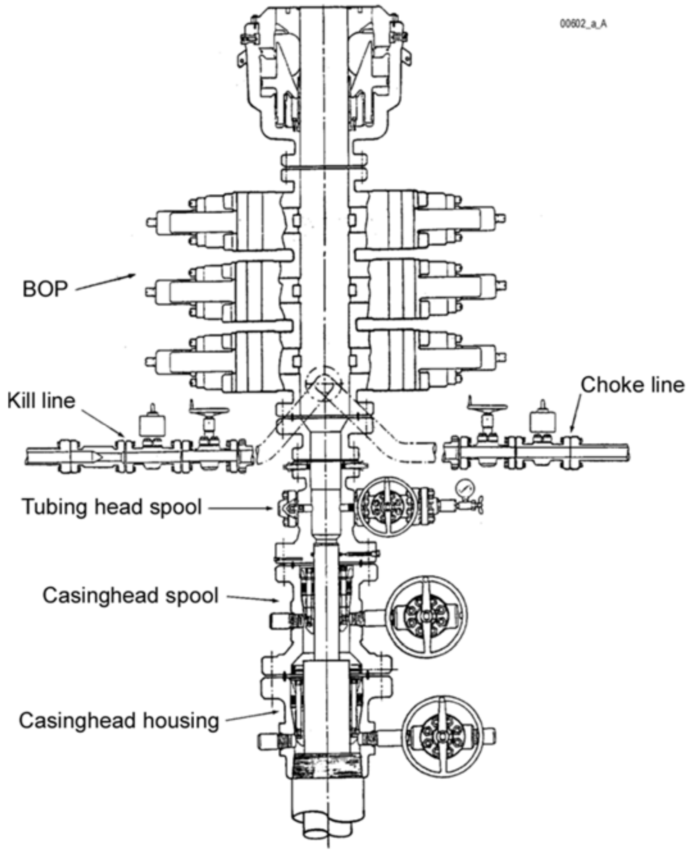
Bag-type BOP





Pipe rams BOP

Wellhead for 6" drilling phase



Fluids used to drill in the pay zone

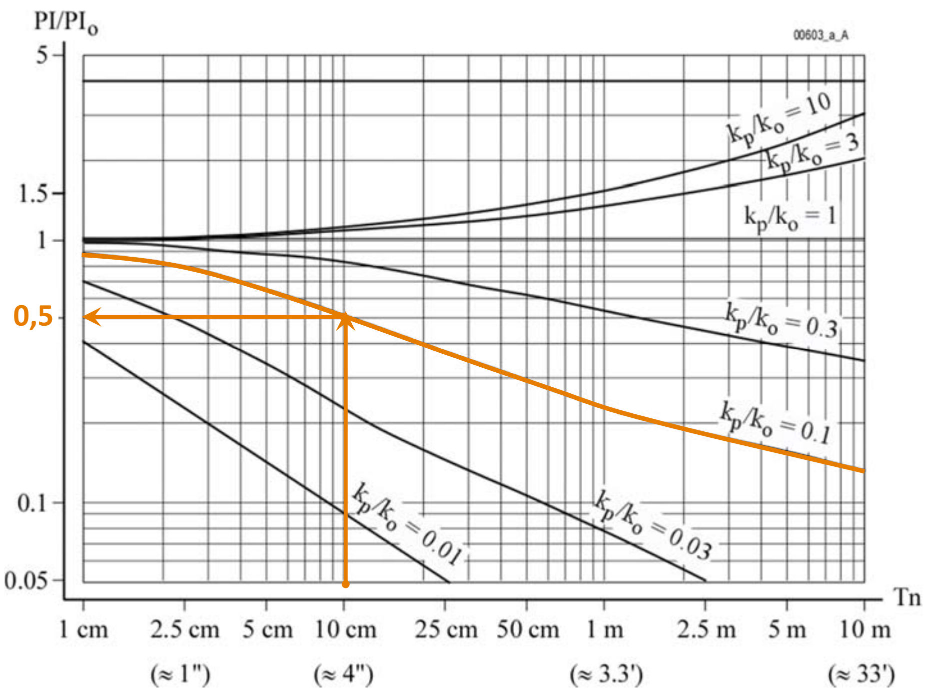
Constraints

- **Safety constraints**
- **Drilling constraints**
- **Formation damage constraints:**
  - Influence on the productivity*
  - Restoration or prevention

⇒ **Required characteristics**
  - (see "Completion fluids")

Influence of near wellbore permeability on productivity index (in radial flow)

Borehole diameter : 8 " 1/2
Drainage radius : 500 m (≈ 1 700 ft)



Tn : Thickness of "plugged" zone from the borehole (8"1/2 drilling)
k_o : Natural permeability of the formation
k_p : Permeability of "plugged" zone
PI_o: Theoretical productivity index (without "plugged" zone)
PI : Actual productivity index (taking into account "plugged" zone)

Completion fluids

- **When?**
  - Drilling
  - Completion
  - Treatment
  - Workover
- **Required characteristics:**
  - Specific gravity ⇒ overpressure
  - Viscosity
  - Filtration rate
  - Compatibility
  - Stability
  - Preparation and handling
  - Price

Completion fluids (cont.)

- **Main completion fluids*:**

Foams	SG = 0.2 to 0.3
Oil base	SG = 0.8 to 1
Water base, solid free	SG = 1 to 2.3
Water base, solid laden	SG = 1 to 2.3

Main completion fluids

- **Foam:**
  - 0.20 to 0.30 dense foam
- **Oil base:**
  - 0.80 to 0.90 diesel or crude
  - 0.85 to 0.95 oil-base or inverted-emulsion mud
  - 0.85 to 1 direct emulsion mud

Main completion fluids (cont.)

- **Water base without solids(*):**
  - 1 to 1.03 water - seawater - brackish water
  - 1 to 1.16 fresh water + KCl
  - 1 to 1.20 fresh water + NaCl
  - 1 to 1.30 fresh water + $MgCl_2$
  - 1 to 1.40 fresh water + $CaCl_2$
  - 1.16 to 1.20 fresh water + KCl + NaCl
  - 1.20 to 1.40 fresh water + NaCl + $CaCl_2$
  - 1.20 to 1.51 fresh water + NaCl + NaBr
  - 1.40 to 1.70 fresh water + $CaCl_2$ + $CaBr_2$
  - 1.70 to 1.80 fresh water + $CaBr_2$
  - 1.80 to 2.30 fresh water + $CaBr_2$ + $ZnBr_2$

(*): Pay attention to the crystallization point, especially with mixtures

Main completion fluids (cont.)

- **Water base plus solids:**
  - 1 to 1.70 fresh water + $CaCO_3$
  - 1 to 1.80 fresh water + $FeCO_3$ (siderite)
  - 1 to 1.80 drilling mud + $CaCO_3$ or $FeCO_3$
  - ~~1 to 2.30 drilling mud + barite~~
  - 1 to 2.30 fresh water + resins
  - 1 to 2.30 oil-base mud or inverted or direct emulsion mud

Additives

- Viscosifiers
- Defoamer
- Fluid-loss control agent
- Emulsifiers (mud containing oil, etc.)
- Weighting material
- Anticorrosion (bactericides, antioxidants)

Annulus fluids

- **Functions and requirements:**
  - To protect the casing $\Rightarrow$ "Non corrosive" fluids
  - No settling $\Rightarrow$ Free solid fluids
  - To decrease efforts on packer, casing, tubing
  - Help to well control
- **Main fluids (depending on the required specific gravity):**
  - Brine
  - Water
  - Diesel oil
  - Oil
- **Protection against corrosion:**
  - High pH (> 9.5)
  - Oxygen scavener
  - Film-forming and antibacterial products:
    - Problem of compability between products

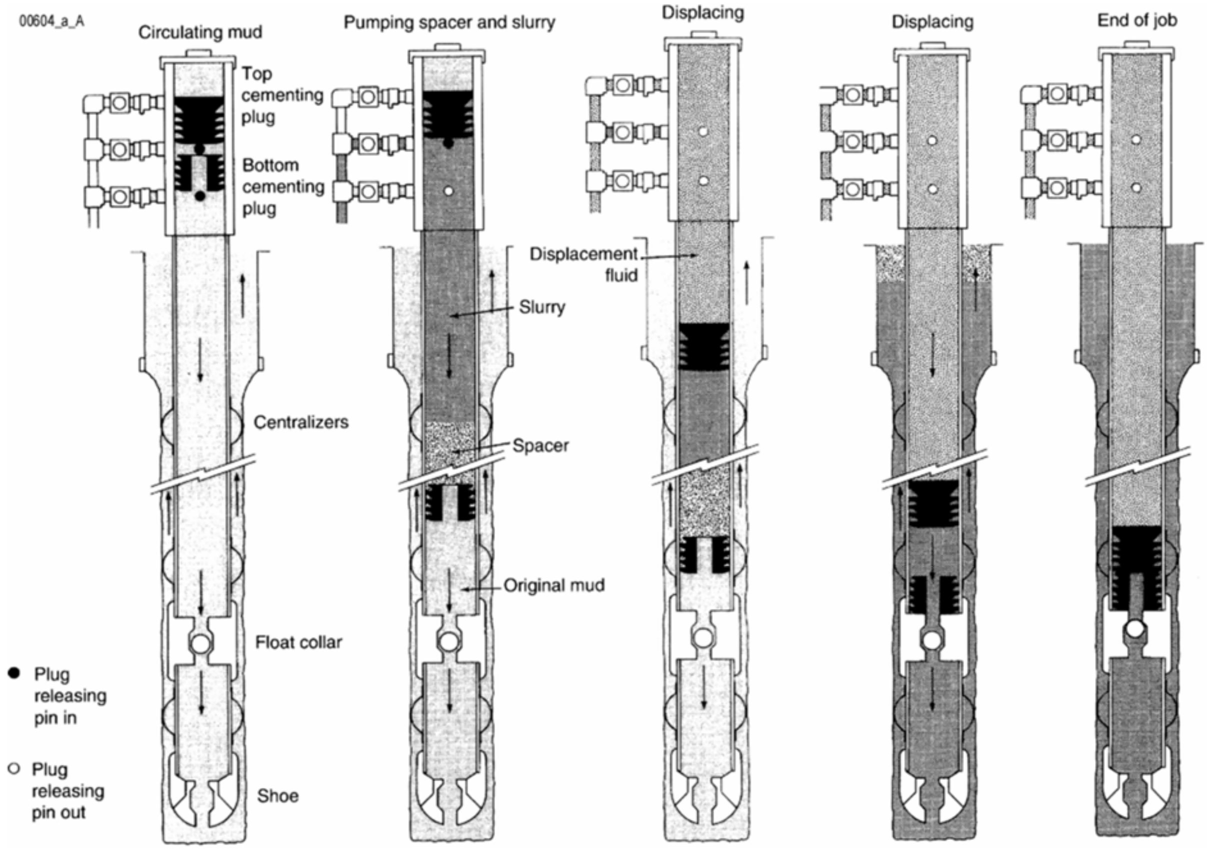
Drilling and casing diameters

- **Effect on productivity index:**
  - Small impact of drilling diameter on PI (unless sand control process)
- **Considerations relative to equipment:**
  - What is important is to have the place required for the production equipment

Main objectives of a primary cementing

- Selectivity
- Borehole holding
- Protection of the casing

Primary casing cementing procedure



Evaluating the cement job

Major flaws encountered after primary cementing

- **Inadequate filling:**
  - Incorrect estimate of volume (caved hole, ...)
  - Losses during displacement
  - Unexpected setting
- **Inadequate seal and/or strength:**
  - Insufficient distance between float collar and shoe
  - Excessive displacement
  - Incomplete displacement of the mud by the slurry (centering, pumping rate, spacer, caved hole, ...)
  - Gas kick
  - No or partially setting
  - Poor quality slurry
  - Deterioration with time

Evaluating methods

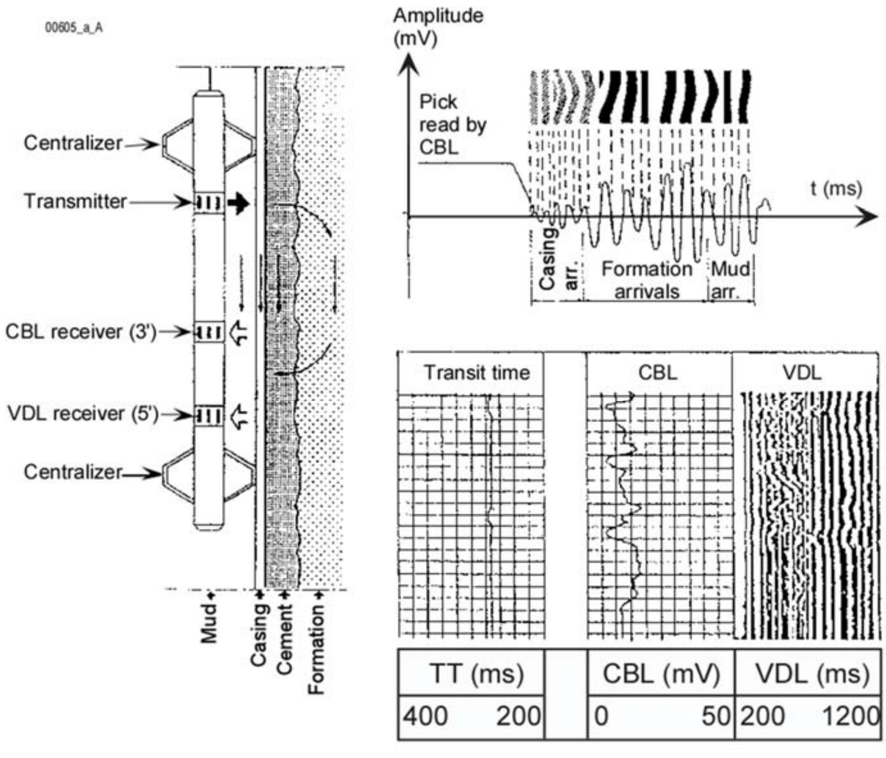
- **Sign during cement job:**
  - Irregularities
- **Direct evaluation:**
  - Pressure test
  - Negative pressure test
- **Indirect evaluation:**
  - Temperature logs
  - Acoustic logs:
    - CBL-VDL (Cement Bond Log – Variable Density Log)
    - CET (Cement Evaluation Tool)
    - USIT (UltraSonic Imager Tool)

CBL-VDL

- **CBL-VDL*:**
  - Low-frequency acoustic wave (20 khz)
  - Vertical path (3 to 5 ft)
  - CBL = Amplitude and transit time of the 1st wave
  - VDL = Complete wave train (positive peaks)
  - Good cement job if CBL low and VDL "formation"
  - Poor cement job if CBL strong and VDL "casing"

Be careful:

- A large number of parameters affect measurements

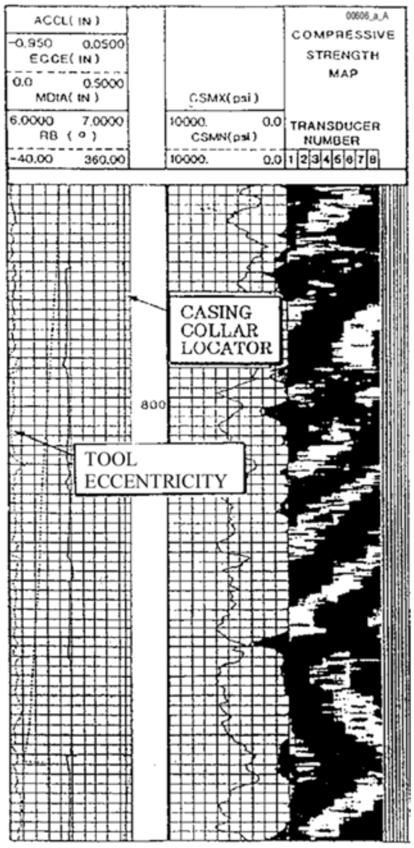


(a) (b)

Principle of the CBL - VDL & standard presentation of a recording

CET

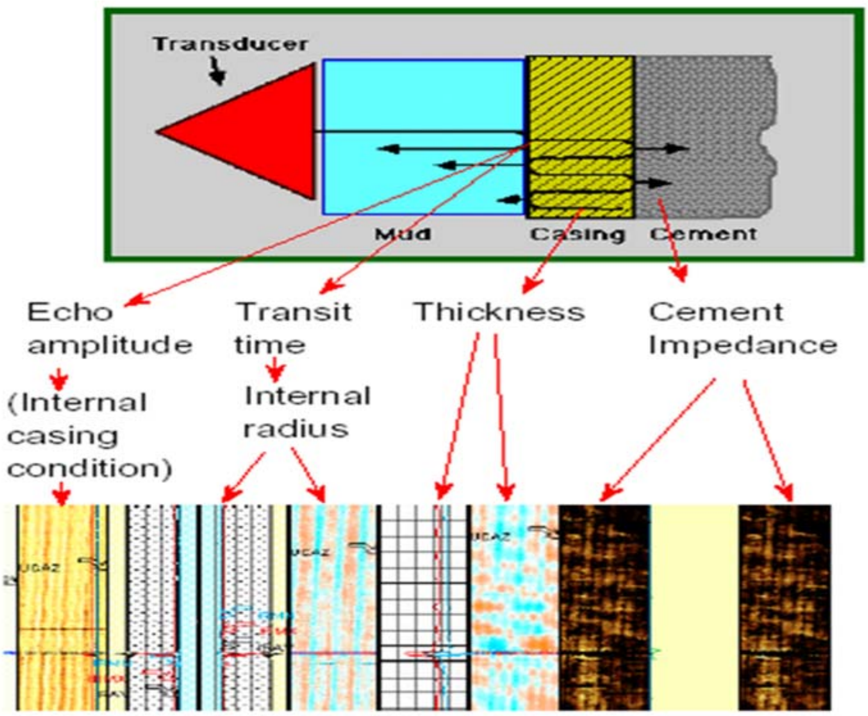
- ▶ **CET*:**
  - High-frequency acoustic wave (500 khz)
  - Measurement of the casing radial (horizontal) resonance according to 8 directions
  - Provides :
    - Average casing diameter and ovalization
    - Min and max compressive strength of the cement
    - "Image" of the cement sheath
  - Good cement job if quick attenuation
    ⇒ black stripe
  - Poor cement job if slow attenuation
    ⇒ white stripe



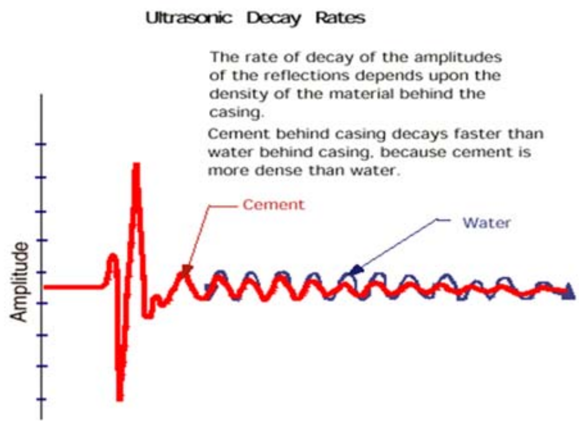
Standard representation of a CET recording

Ultrasonic measurements

Ultrasonic reflection principles



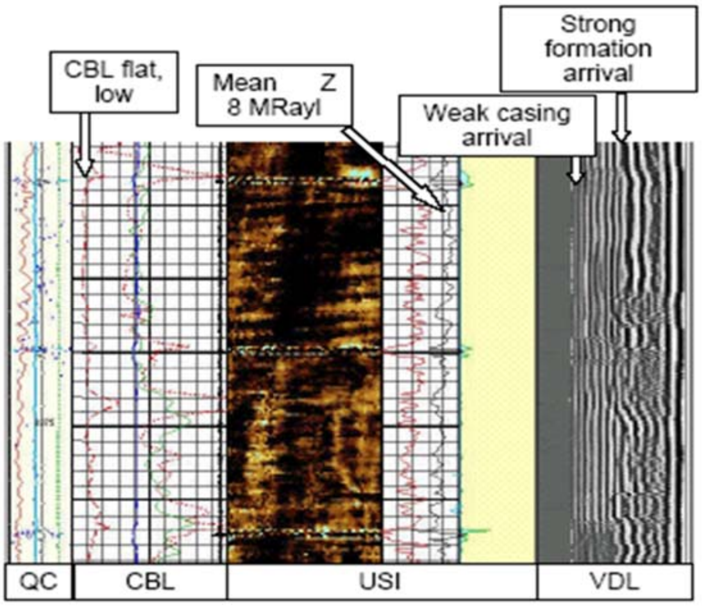
Ultrasonic decay rate

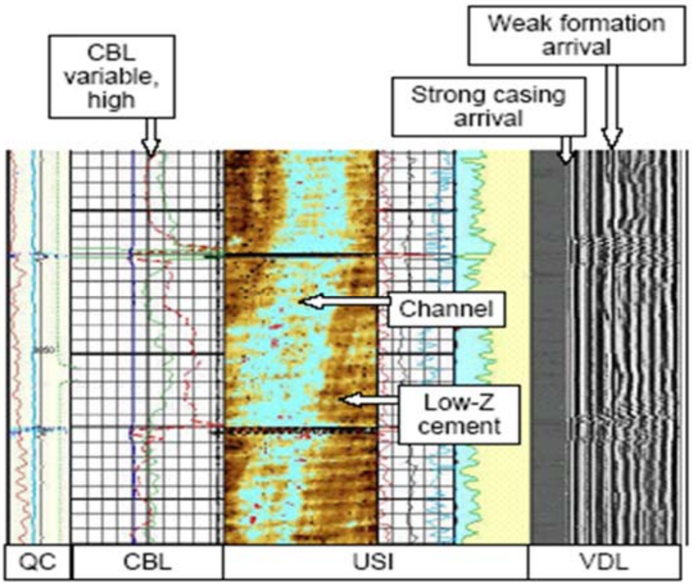


Acoustic Impedance of material in contact with casing

USIT & CBL/VDL

Good Cement





Mud channel
& contaminated cement

Remedial cementing

Objective & Basic methods

- **Objective:**
  - To restore an inadequate primary cement job:
    - Inadequate filling
    - Inadequate seal and/or strength
- **Basic methods:**
  - Squeeze:
    - Filtering due to differential pressure
  - Possibly: circulating
  - The best: prevention

Applications

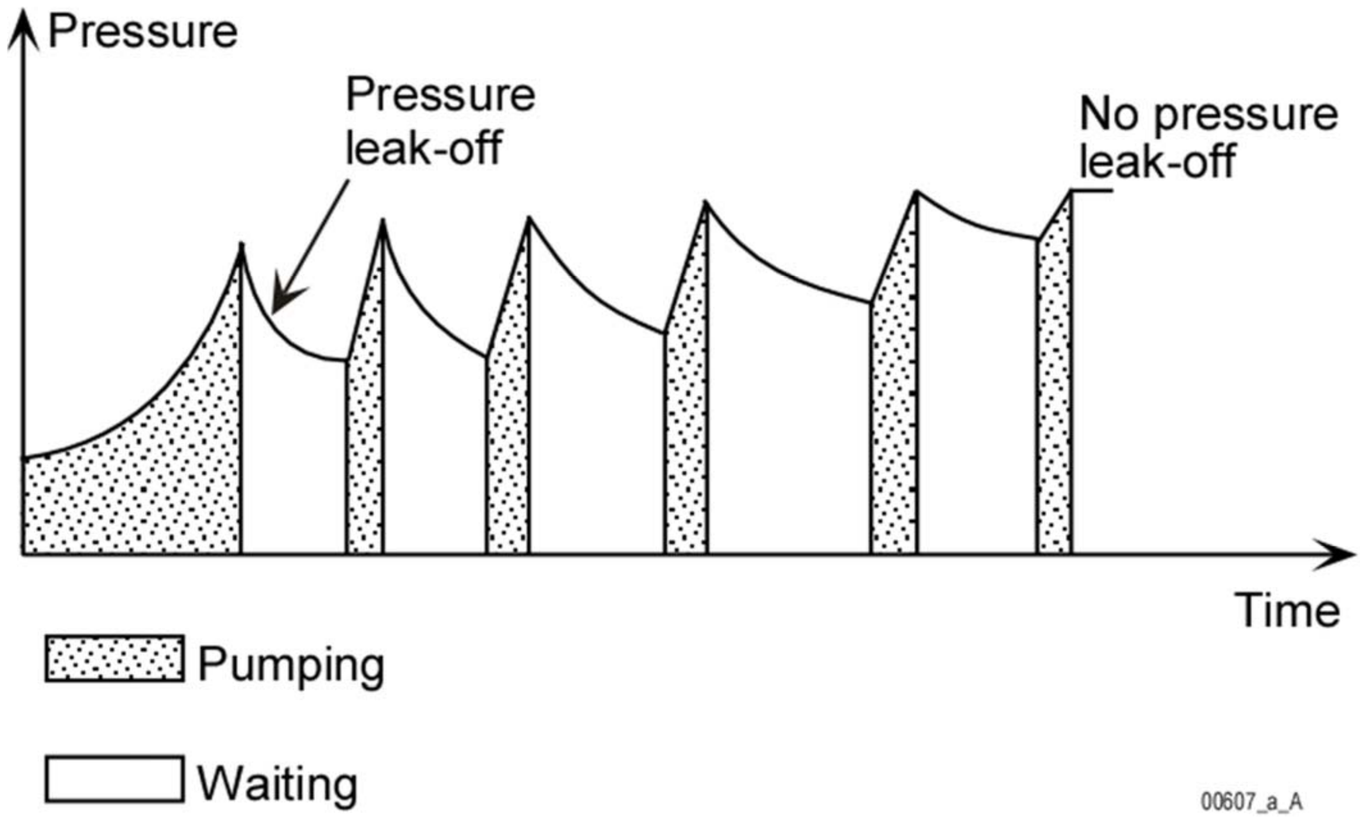
- To restore a primary cement job
- To restore isolation between zones
- To reduce WOR or GOR due to coning
- To isolate a water or gas zone
- To abandon a depleted pay zone
- To repair a leaky casing

Low-pressure squeeze

- **Principle:**
  - Pumping with $P_{BH} < P_{frac}$
- **Key parameters:**
  - Perforations and channels free of plugging fluids (drilling mud, etc.)
  - Permeable enough formation
  - Pumping pressure < P_{frac}:
    Mind out: variation of the surface pressure non representative of the variation of the bottom hole pressure

  ⇒ Proceed first to perforation cleaning & injectivity test
- **Pumping techniques (consider also the tool string to be used):**
  - Continuous
  - Stop and start (hesitation squeeze)*
  - Combination of these two techniques

"Pressure vs time" diagram (during hesitation squeeze)



High-pressure squeeze

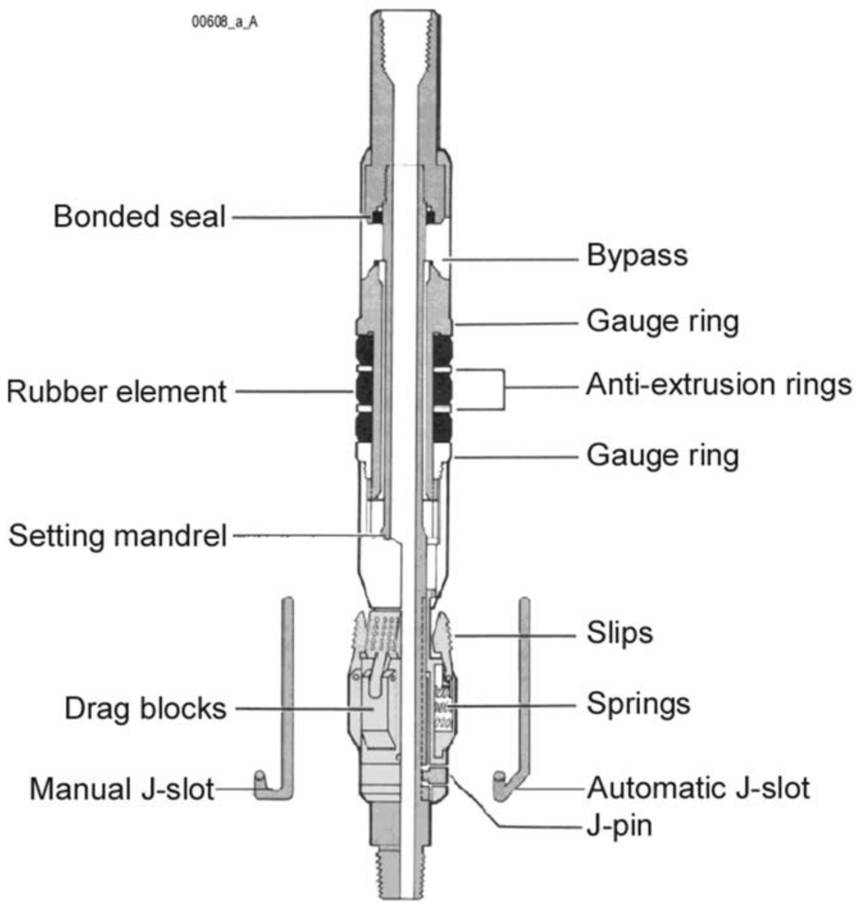
- **Principle:**
  - To deliberately fracture the zone to be treated
- **However:**
  - A large number of drawbacks
- **As a result:**
  - Technique non commonly used
  - Still has a number of applications

Squeeze procedures & relevant tool strings

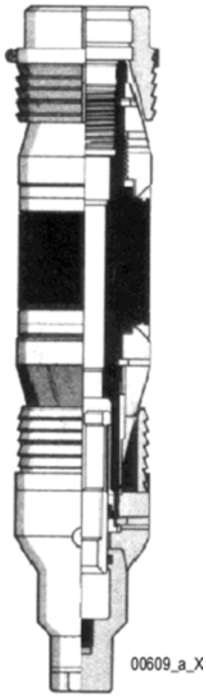
- **Operations to be done:**
  - To place the slurry at a specified point
  - Possibly, to isolate this zone...
  - To inject the slurry under pressure
- **Required equipment:**

  Drillpipes:
  - Alone, or
  - With a squeeze packer*, or
  - With a cement retainer*,and possibly
  - A bridge plug* (retrievable or permanent)

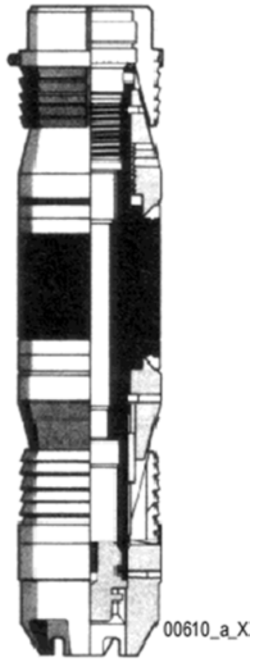
Positest packer



Cement retainer & Bridge plug



Cement retainer

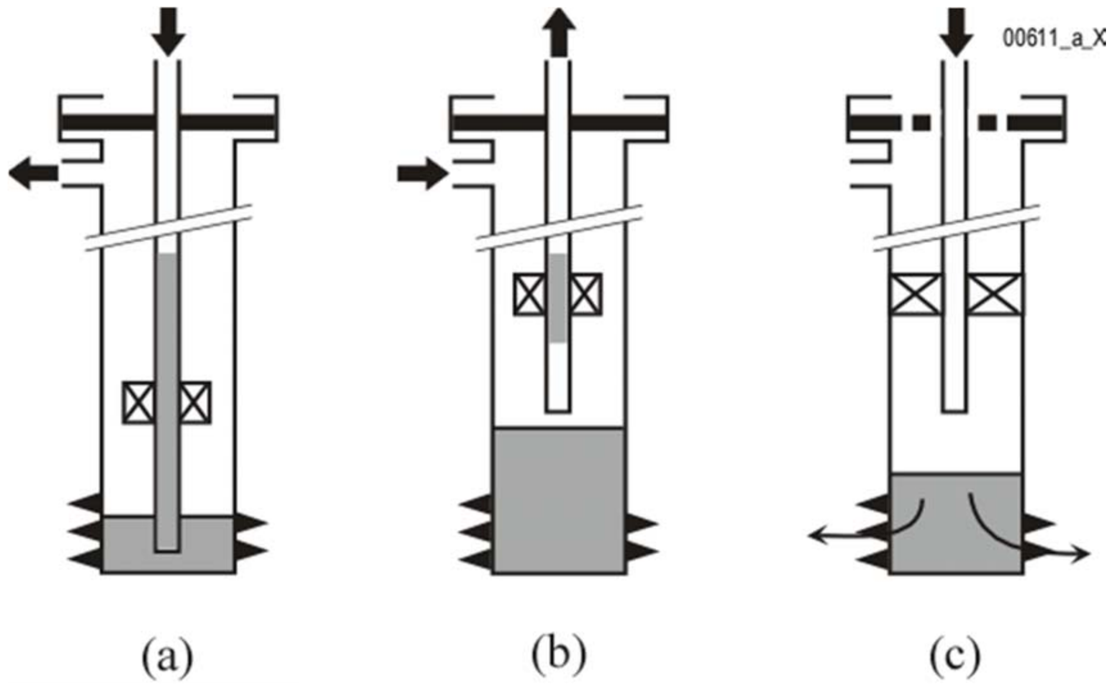


Bridge plug

Squeeze procedures & relevant tool strings

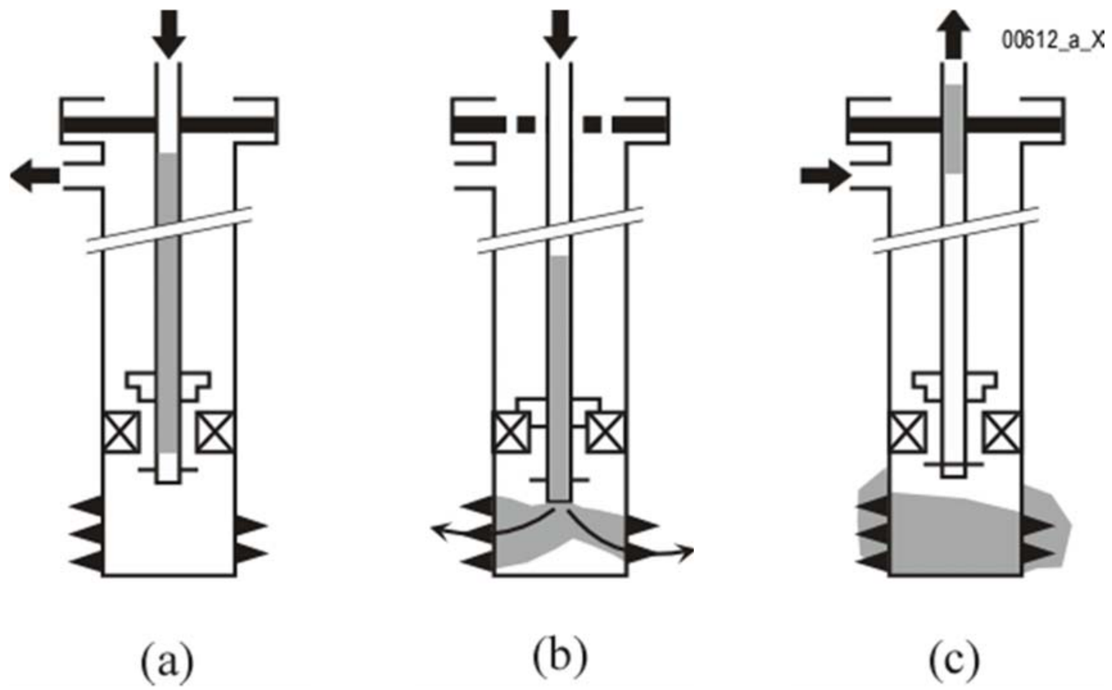
- **Slurry squeeze with the slurry displaced to the perforation depth by circulating***
- **Slurry squeeze with the slurry displaced to the perforation depth by circulating then squeezing***
- **Slurry injection while circulating***
- **Adding a bridge plug**

Slurry squeeze with the slurry displaced to the perforation depth by circulating (with long tail pipe & packer [or drill pipes alone])

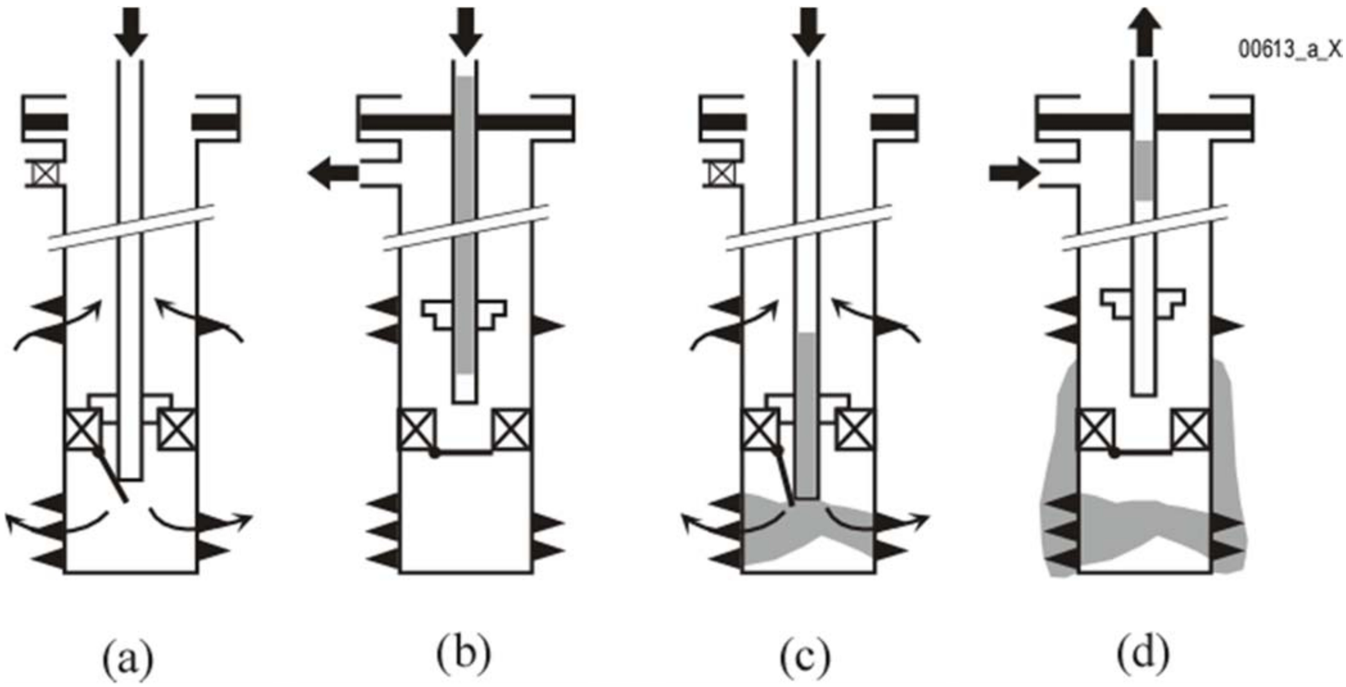


Slurry squeeze with the slurry displaced to the perforation depth by circulating

- then squeezing (with short tail pipe & packer or cement retainer)



Slurry injection while circulating
(with cement retainer)



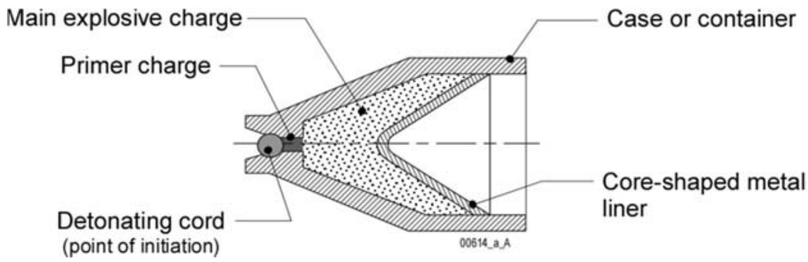
Notes

Perforating

Contents

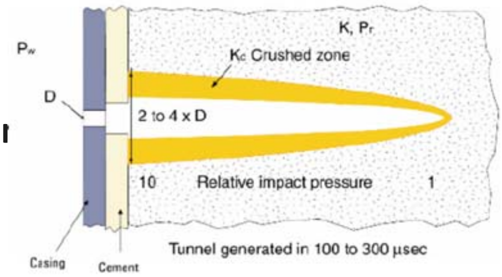
Objective & existing processes

- **Objective:**
  - To re-establish the best possible connection between the pay zone and the borehole
- **Existing processes:**
  - Bullet
  - Mechanical perforator
  - Hydraulic perforator
  - . . .
  - Shaped charges*



Shaped charge

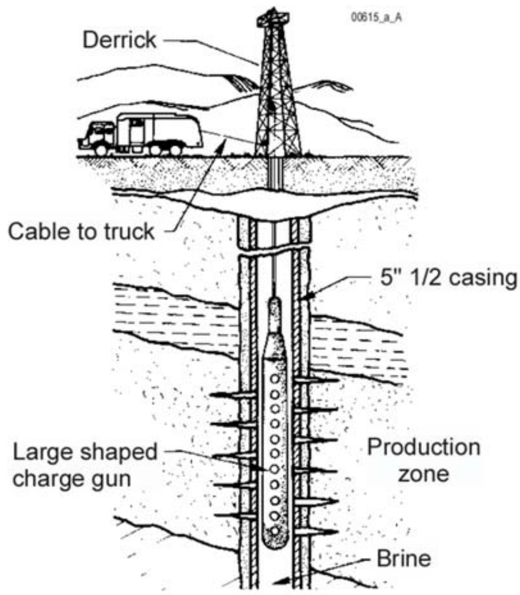
Note: - **Pay attention to productivity***
- **Efficiency depends on the gun selection & the perforating method**



Perforation tunnel & Crushed zone

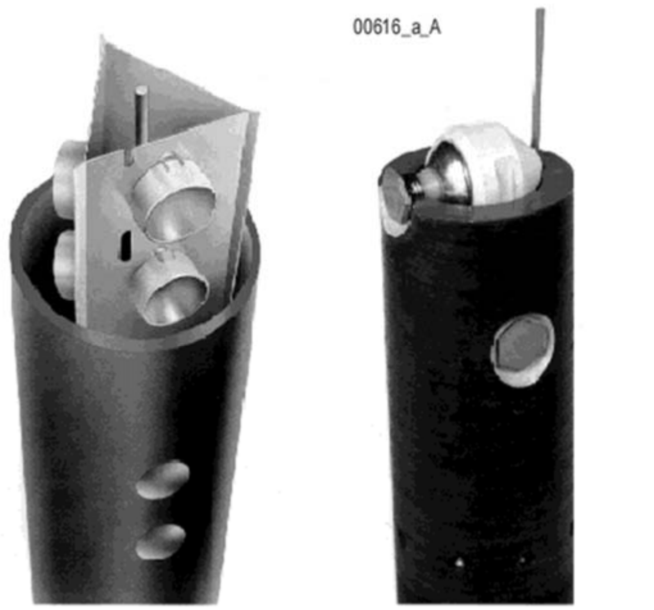
Overbalanced pressure perforating before equipment: Method

- **Principle:**
  - Before equipment installation
  - Well full of completion fluid
- **Advantages (see also advantages of the corresponding carriers):**
  - Good penetration
  - Multiple shot directions
- **Drawbacks (see also drawbacks of the corresponding carriers):**
  - Overbalanced conditions
    ⇒ plugging
  - Subsequent cleaning hard to do
  - (Safety condition not as good for further operations)



Overbalanced pressure perforating before equipment: Corresponding carriers

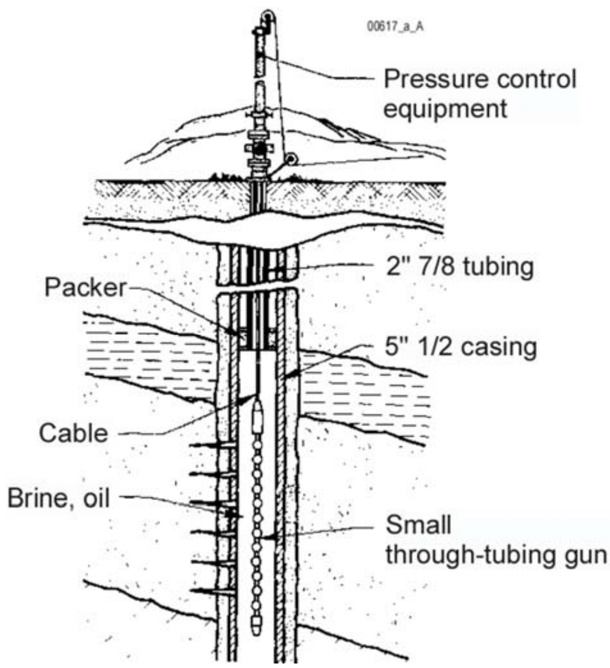
- **Retrievable casing guns (run with an electrical cable):**
  - Leakproof guns
  - Run with electric cable
  - Shot density: 4 (to 12 and more) SPF
  - Phasing: 90° - 120° - 180°
  - Unit length: 6 to 11 ft
  - Can be assembled together
- **Advantages:**
  - Good reliability
  - Charges isolated from fluid and pressure
  - No debris in the well
  - Selective firing
  - No casing deformation
- **Drawbacks:**
  - Limited length run in at one time
  - Difficult run in highly deviated well



High shot density   Standard density

Underbalanced pressure perforating after equipment: Method

- **Principle:**
  - After equipment installation, Christmas tree included
  - Well full of "light" liquid
- **Advantages (see also advantages of the corresponding carriers):**
  - No or reduced plugging
  - Well equipment in place (safety)
- **Drawbacks (see also drawbacks of the corresponding carriers):**
  - Small gun ⇒ small shaped charges (*) ⇒ smaller penetration (*)
  - Only one shot direction (depending the gun size) (*)
  - Debris in the well (if semi or fully expendable carriers)
  - Mind out excessive ΔP:
    - reservoir deconsolidation
    - carrier possibly dragged up
  - (*) Except for pivot gun

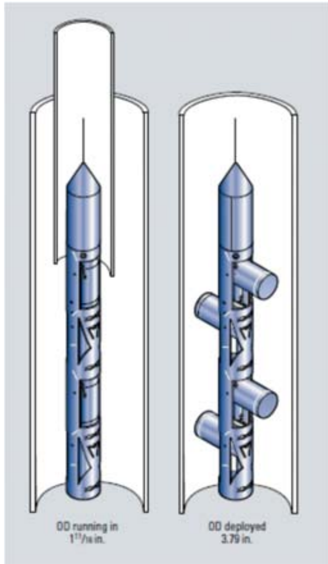


Underbalanced pressure perforating after equipment:

Corresponding carriers

- **Retrievable through tubing guns***
  (run with an electrical cable):
  - Refer to "Retrievable casing gun"
  - But:
    - Small charge ⇒ small or very small penetration (except for "pivot guns")
    - Gun expansion ⇒ risk to get stuck when pulling up
- **Semi* or fully expendable carriers**
  (run with an electrical cable):
  - Thinner carrier ⇒ charges a little bigger
  - But:
    - No selective firing
    - Debris in the well
    - Casing and cement sheath possibly damaged
    - More restricted in pressure and temperature
- **And, for both of them:**
  - Difficult run in in highly deviated well

Scallop gun



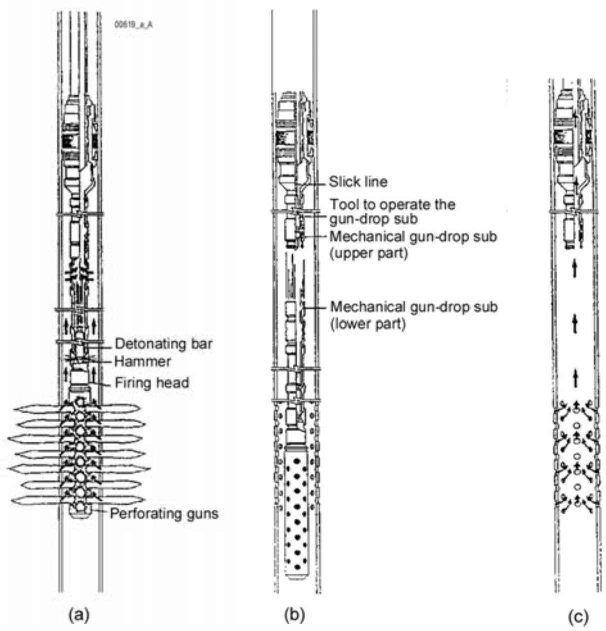
Pivot gun

Enerjet

TCP perforating

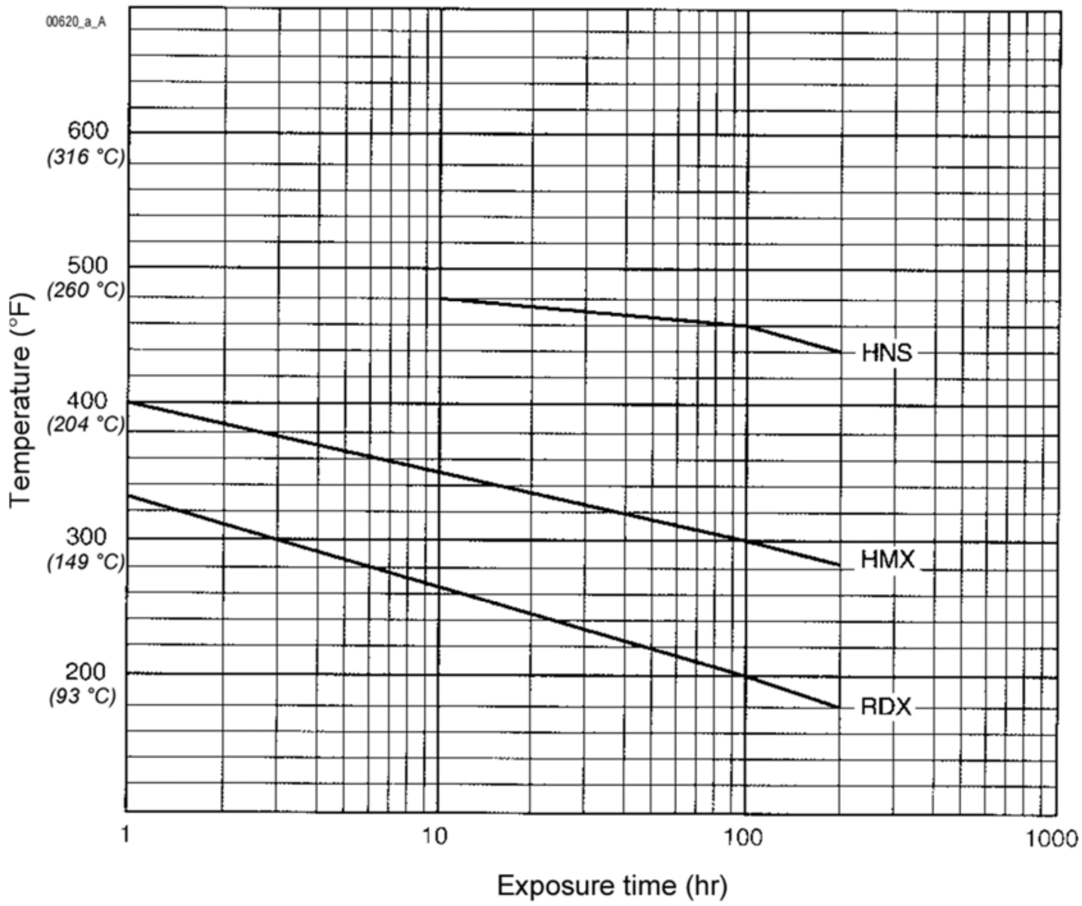
(TCP = Tubing Conveyed Perforator)

- **Principle*:**
  - Guns run in directly with the tubing
  - Underbalanced pressure when fired
- **Advantages:**
  - Good penetration
  - No or reduced plugging
  - Perforating in one single operation:
    - Very long stretch of casing
    - High shot density
  - No problem in highly deviated well
- **Drawbacks:**
  - "Trash dump" has to be drilled
    or
    No access opposite the pay zone for wireline jobs
  - Charge performances decrease with temperature and time*
  - Impossible to check that all the charges have been fired
  - If "misfire":
    - Time-consuming
    - Safety problems



Basic TCP procedure

Time-temperature ratings for explosives



TCP perforating

(TCP = Tubing Conveyed Perforator)

- **In practice, mainly used with a temporary string:**
  - To perforate a long stretch of casing
  - When gravel packing:
    - Large diameter perforations
    - High shot density
  - To perform perforations and DST (Drill Test Stem) in one single operation:
    - Gain in safety
    - Gain in time
    - but:
    - Risk to damage the recorders

TCP perforating

(TCP = Tubing Conveyed Perforator)

- **Specific equipment:**
  - Guns: cf "retrievable guns"
  - Firing head
  - Gun release system(*)
  - Circulating devices (with or without a rupture disk)
  - Isolation device
  - Shock absorbers
  - Depth reference

- ***: equipment actuated:**
  - Mechanically
  - Hydraulically
  - Electrically
  - Automatically

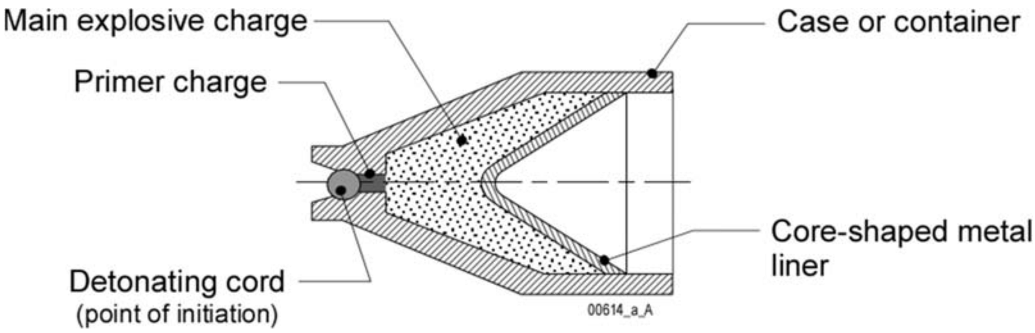
Choice of the method

Trade-off between:

- **Well constraints:**
  - Plugging (whether or not?, thickness of the damage zone)
  - Risk of sand intrusion
  - Type of effluents
  - Reservoir characteristics
  - State of the well (casing, cement job)
  - Safety
- **And optimum perforating conditions(*) :**
  - Underbalanced shooting
  - Clean fluid in the well
  - Large-diameter perforator
  - High-performance charges
  - Clearing as soon as possible after shooting
- ***: Conditions which are not necessarily compatible with one another**

Shaped charges principle

- **Five components:**

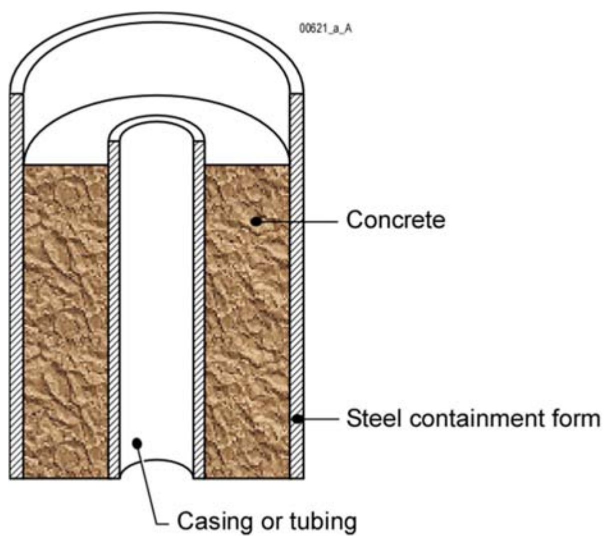


- **Perforation dimensions depend on:**
  - The amount of explosive load
  - The type and angle of the metal cone
  - The distance "shape charge - target" (stand-off)
  - The density of the target

Note:
- Velocity of the jet of gas: 7000 m/s (20, 000 ft/s)
- Pressure on target: 30,000 MPa (5 . 10^6 psi)
- Velocity of slug: 300 to 1000 m/s (1000 to 3000 ft/s)

API RP 43 Standard

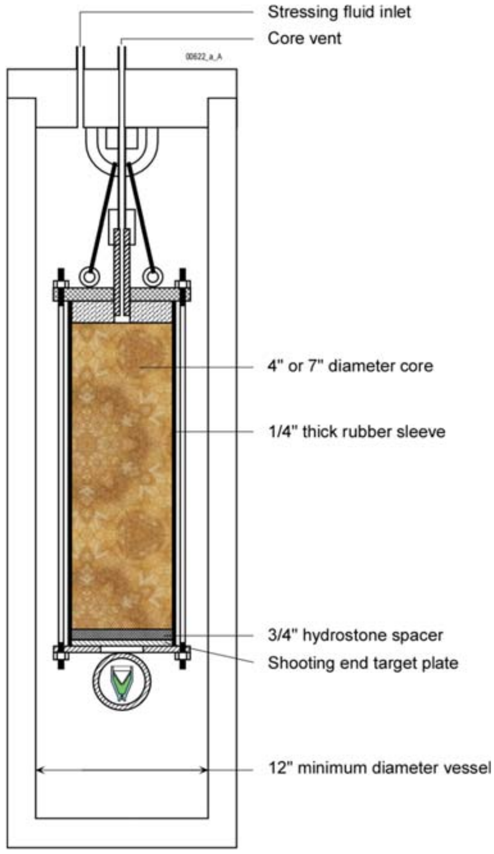
- **Preliminary note:**
  - Only sections 1 & 2 are necessary for the certification
  - Sections 3 & 4 are optional
- **Section I:**
  (concrete target*, ambiant temperature & atmospheric pressure)
  - Total depth of penetration
  - Hole diameter
  - Burr height



API concrete target

API RP 43 Standard (cont.)

- **Section II:**
  (stressed Berea sandstone with wellbore pressure applied*: 3000 psi)
  - Total depth of penetration
  - Faceplate hole diameter



API section II target

Certification data sheet (API RP 43 - section I & II)

API FORM 43F

CERTIFICATION DATA SHEET
PERFORATING SYSTEM EVALUATION, RP 43, SECTIONS 1 AND 2

Service Company ____ Explosive Weight ____ gm, ____ powder, Case Material ____
Gun OD & Trade Name ____ Max. Temp, F ____ 1 hr ____ 3 hr ____ 24 hr ____ 100 hr ____ hr
Charge Name ____ Maximum Pressure Rating ____ psi, Carrier Material ____
Manufacturer Charge Part No. ____ Date of Manufacture ____ Shot Density Tested ____ shots/ft
Gun Type ____ Recommended Minimum ID for Running ____ in.
Phasing Tested ____ degrees, Firing Order ____ Top down, ____ Bottom up Available Firing Mode ____ Selective, ____ Simultaneous
Debris Description ____ Debris Weight ____ gm/charge, Debris ____ in.³/charge
Remarks ____

SECTION 1 — CONCRETE TARGET

Casing Data ____ OD, Weight ____ lb/ft, ____ API Grade, Date of Concrete Test ____
Target Data ____ OD, Briquet Compressive Strength ____ psi, Age of Target ____ days

Shot No.	No. 1	No. 2	No. 3	No. 4	No. 5	No. 6	No. 7	No. 8	No. 9	No. 10
Clearance, in.										
Casing Hole Diameter, Short Axis, in.										
Casing Hole Diameter, Long Axis, in.										
Average Casing Hole Diameter, in.										
Total Depth, in.										
Burr Height, in.										

Shot No.	No. 11	No. 12	No. 13	No. 14	No. 15	No. 16	No. 17	No. 18	No. 19	No. 20	Average
Clearance, in.											
Casing Hole Diameter, Short Axis, in.											
Casing Hole Diameter, Long Axis, in.											
Average Casing Hole Diameter, in.											
Total Depth, in.											
Burr Height, in.											

Remarks ____

SECTION 2 — BEREA SANDSTONE CORE TARGET

Berea Bulk Porosity, ____ %
Date of Berea Test ____ %

Shot No.	No. 1	No. 2	No. 3	No. 4	No. 5	No. 6	Average
Faceplate Hole Diameter, Short Axis, in.							
Faceplate Hole Diameter, Long Axis, in.							
Average Faceplate Hole Diameter, in.							
Total Depth, in.							

CERTIFICATION

Type of Certification: ☐ Self ☐ Third Party

I certify that these tests were made according to the procedures as outlined in API RP 43: Recommended Practices for Evaluation of Well Perforators, Fifth Edition, January 1991. All of the equipment used in these tests, such as the guns, jet charges, detonator cord, etc., was standard equipment with our company for use in the gun being tested, and was not changed in any manner for the test. Furthermore, the equipment was chosen at random from stock and therefore will be substantially the same as the equipment which would be furnished to perforate a well for any operator.

____ CERTIFIED BY
____ RECERTIFIED (Company Officer) (Title) (Date) (Company) (Address)

API RP 43 Standard (cont.)

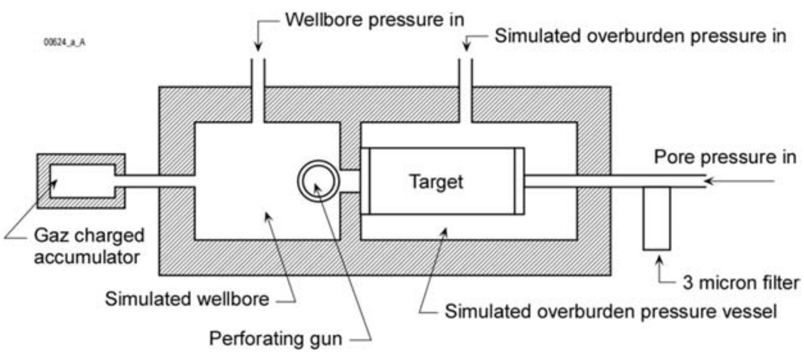
▶ Section III (elevated temperature and atmospheric pressure):

- Total depth penetration
- Faceplate hole diameter
- Faceplate hole roundness
- Note: data expressed as a ratio of the average hot/cold measurements

API RP 43 Standard (cont.)

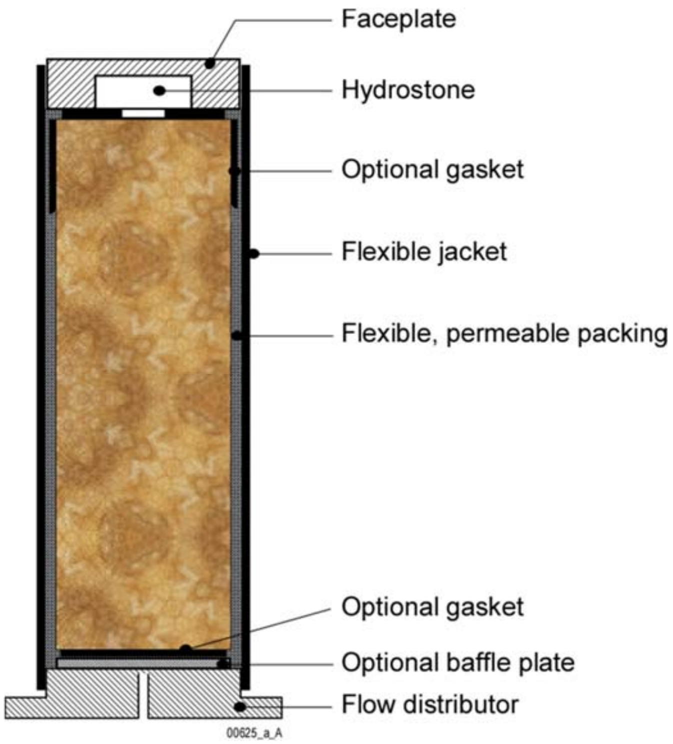
▶ Section IV (flow performance of a perforation):

- CFE (Core Flow Efficiency: ratio between observed flow and calculated flow)
- Test conditions*:
  - Confining pressure: 4500 psi (310 bar)
  - Pore pressure: 1500 psi (103 bar)
  - Wellbore pressure: 1000 psi (69 bar)
  - Differential pressure during flowing: 50 psi (3.45 bar)

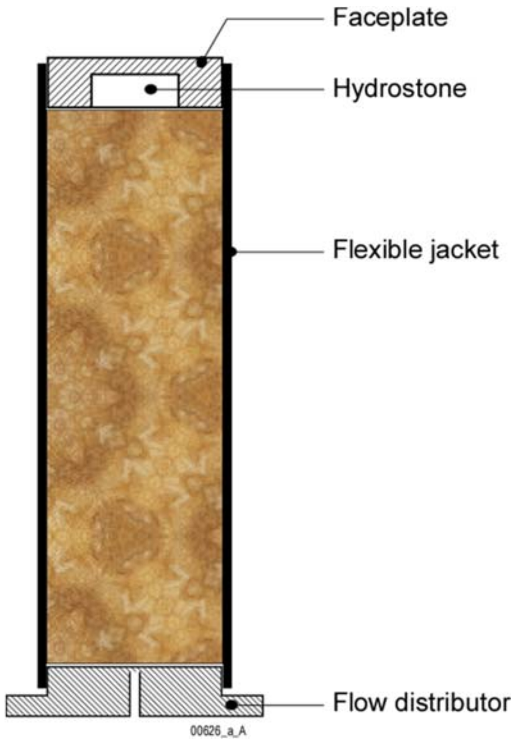


Schematic of a typical test equipment (API RP 43 - section IV)

Typical arrangements (API RP 43 - section IV)



Radial flow geometry



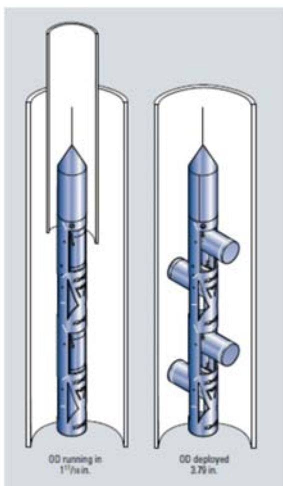
Axial flow geometry

Through-tubing gun performance

(from Schlumberger)

Perforating gun performance (API statistics)							
				API RP 43 - Section 1			
Gun designation	Shot density (SPF)	Number of shot directions	Explosive load (g)	Casing size (in)	Casing weight (lbm/ft)	Entrance hole (in.)	Penetration (in.)
Scallop guns							
1 11/16	4	1	3.2	4 1/2	11.6	0.22	9.2
2 1/8	4	1	6.5	4 1/2	11.6	0.25	13.5
	4	2	6.5	4 1/2	11.6	0.22	12.9
	4	6	6.5	4 1/2	11.6	0.22	14.1
	4	6	6.5	4 1/2	11.6	0.36	5.9
Pivot guns							
1 11/16	4	2	22	4 1/2	11.6	0.38	27.8
Enerjet guns							
1 11/16	4	1	8.0	4 1/2	11.6	0.26	16.7
	4	8	8.0	4 1/2	11.6	0.25	15.6
2 1/8	4	1	14.0	5 1/2	17.0	0.30	27.5
	4	1	14.0	5 1/2	17.0	0.51	10.5
	4	8	14.0	5 1/2	17.0	0.29	22.4
2 1/2	4	8	21.0	7	32.0	0.36	28.4

Scallop gun



Pivot gun

00618_a_X

Enerjet

Casing gun performance

(from Schlumberger)

Perforating gun performance (API statistics)							
				API RP 43 - Section 1			
Gun designation	Shot density (SPF)	Number of shot directions	Explosive load (g)	Casing size (in)	Casing weight (lbm/ft)	Entrance hole (in.)	Penetration (in.)
Port plug guns							
3 1/8	4	4	16.0	4 1/2	11.6	0.33	21.4
4	4	4	22.5	5 1/2	17.0	0.37	27.6
High shot density guns							
2 1/2	6	6	10.5	3 1/2	9.2	0.29	17.3
2 7/8	6	6	15.0	4 1/2	11.6	0.30	22.0
3 3/8	6	6	21.3	4 1/2	11.6	0.40	21.0
	6	6	24.0	4 1/2	11.6	0.56	12.9
4 1/2	12	8	21.3	7	32.0	0.4	17.2
	12	6	24.0	7	32.0	0.7	7.9
	21	6	19.0	7	32.0	0.77	5.9
5	12	8	21.3	7	32.0	0.39	22.8
	12	8	24.0	7 5/8	33.7	0.61	9.8
	21	6	19.0	7 5/8	33.7	0.74	7.9
7	12	6	38.8	9 5/8	47.0	0.39	40.0
	12	8	66.0	9 5/8	47.0	1.07	9.3

Effect of sand in perforation tunnels

Effect of sand in perforation tunnels

- $Q_{oil} \approx 10\ m^3/d/m \approx 20$ bpd/ft
- $B_o \approx 1.4$
- Perforations:
  - 4 SPF
  - Diameter: 1 cm (0.4 in)
  - Length: 5 cm (2 in)
    (through casing and cement sheath)
- Oil viscosity: 1 cP
- Sand permeability: 300 mD

$\Rightarrow$ ΔP perf = ?

Darcy's law

- **Linear flow:**

$$Q_{(m^3/d)} = 0.00864\ \frac{K_{(mD)} \times A_{(m^2)} \times \Delta P_{(bar)}}{B \times \mu_{(cP)} \times L_{(m)}}$$

$$Q_{(bbl/d)} = 1.127 \times 10^{-3}\ \frac{K_{(mD)} \times A_{(ft^2)} \times \Delta P_{(psi)}}{B \times \mu_{(cP)} \times L_{(ft)}}$$

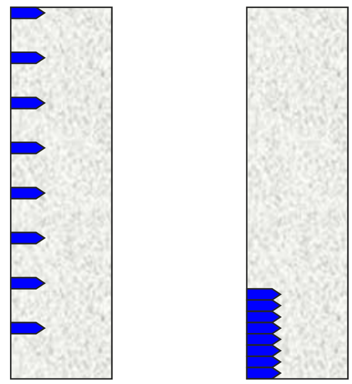
- **Radial circular flow:**

$$Q_{(m^3/d)} = 0.0236\ \frac{K_{(mD)} \times H_{(m)} \times \Delta P_{(bar)}}{B \times \mu_{(cP)} \times \mathrm{Log}\,(R/r)}$$

$$Q_{(bbl/d)} = 3.08 \times 10^{-3}\ \frac{K_{(mD)} \times H_{(ft)} \times \Delta P_{(psi)}}{B \times \mu_{(cP)} \times \mathrm{Log}\,(R/r)}$$

Main parameters affecting the productivity of a zone produced by perforating

- **Number of effective perforations:**
  - In relationship with:
    - Perforating and cleaning methods
    - Shot density
  - High density may reduce pressure losses in perforations and vicinity
- **Distribution of perforation:**
  (height spreading covering the producing zone)
  - Depends on:
    - Reservoir considerations
    - The perforations effectively opened
  - Consider 8 zones of 2.5 m perforations:
    - Spread out on a 100 m reservoir gives PI twice higher than if perforations in lower part (function of kv)



Main parameters affecting the productivity of a zone produced by perforating (cont.)

- **Perforation penetration:**
  - Penetration depends on:
    - The explosive load(*)
    - The shape and type of cone
    - The clearance(*)
    - The compressive strength of the rock
  - Key parameter: penetration / depth of the damage zone

***: In relationship with the gun size and so with perforating method**

Main parameters affecting the productivity of a zone produced by perforating (cont.)

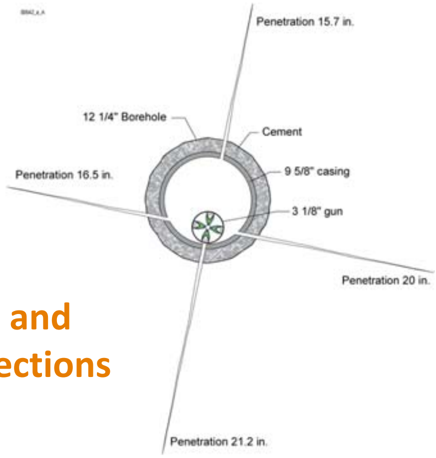
Characteristics of the crushed zone

- In relationship with:
  - The type of explosive
  - The shape and type of cone
  - The target formation
- Expressed to a certain extent by the CFE (Core flow efficiency : ratio [usually from .7 to .9] between the flow rate measured during the API test and the theoretical flow rate of a "perforation", with the same penetration and diameter, obtain by "drilling")

Number of shooting directions (phasing)

- Depends on (because of penetration):
  - Gun diameter / casing diameter*

  and so, on:
  - Perforating method



Effect of gun size and number of shot directions

Main parameters affecting the productivity of a zone produced by perforating (cont.)

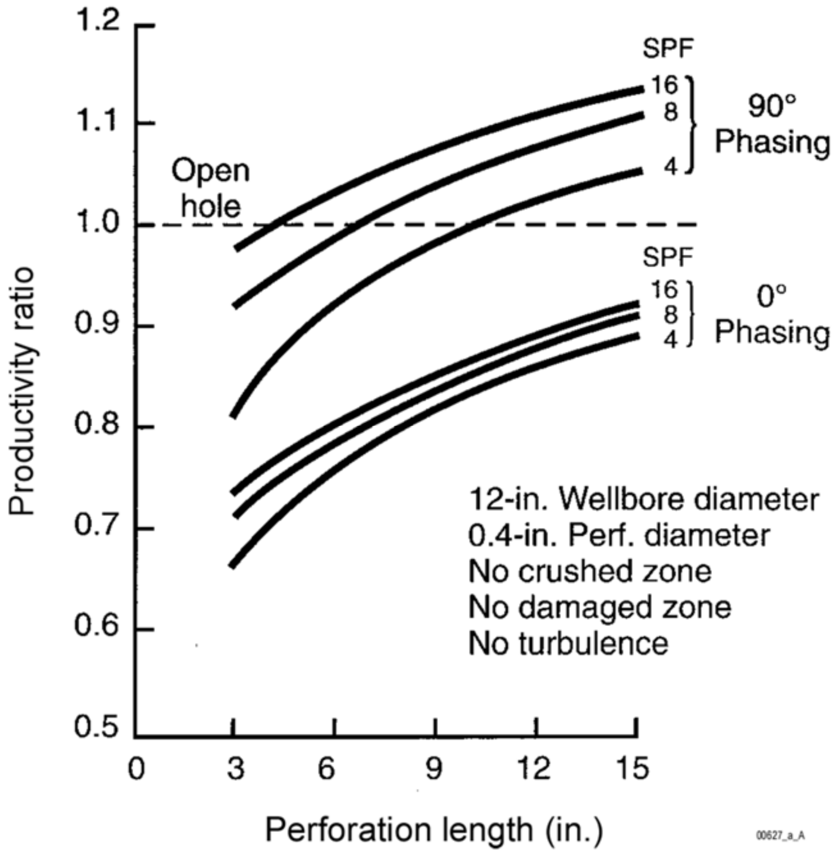
Perforation hole diameter:

- Essential only if:
  - Sand control
  - Very high flow per perforation
  - Limited entry technique
- Depends on :
  - The cone angle
  - The gun - casing clearance, and so
  - The gun diameter, perforating method

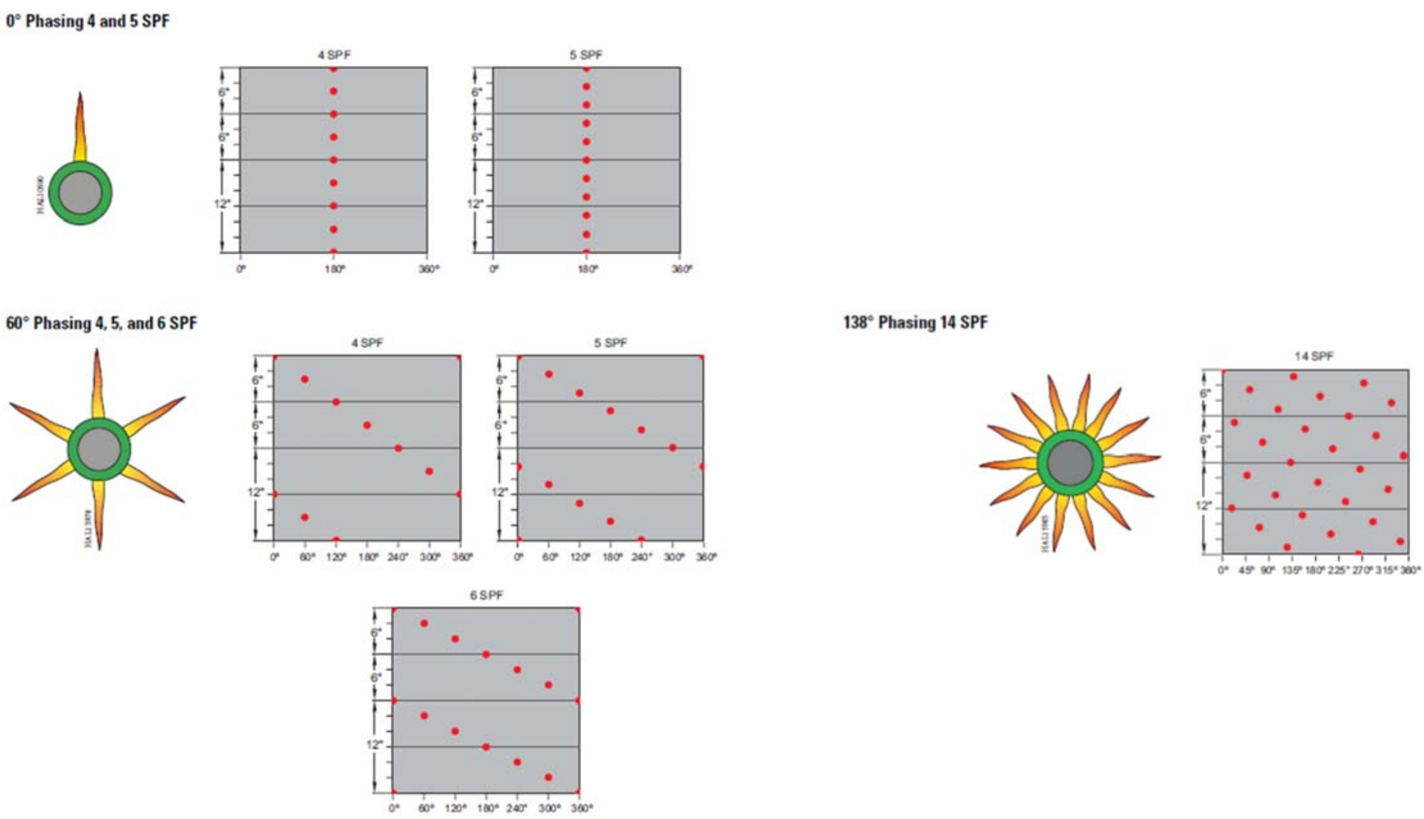
Illustration of some parameters

  - Refer to the charts*

Influence of the perforation length, phasing and shot density on the productivity ratio



Phasing & shot density



Safety

- **Electrical system check before perforating**
- **Basic safety (1/2):**
  - Perforation not performed:
    - During storms
    - At night, except if…
  - If perforating carried out with "overbalanced pressure before equipment installation":
    - Completion fluid
    - Drilling BOPs
    - High-pressure pump connected to the well
    - Monitoring of the well stability when:
      - Firing
      - Pulling out

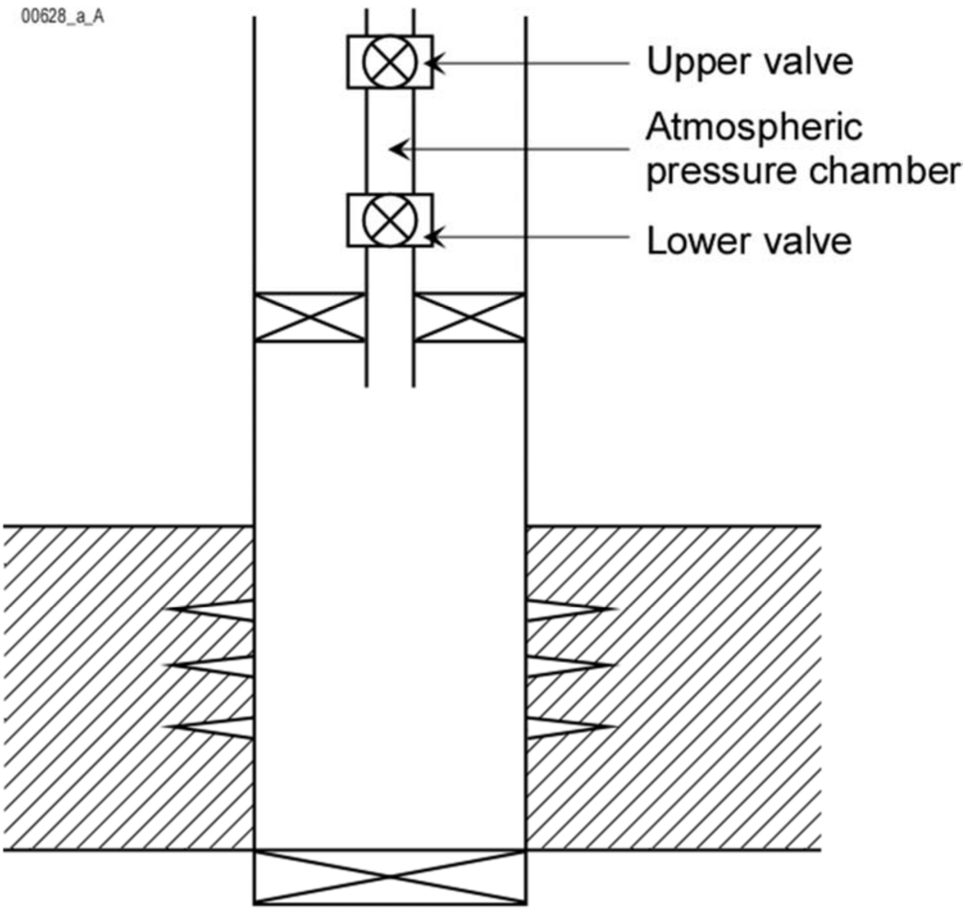
Safety (cont.)

- **Basic safety (2/2):**
  - If perforating carried out with "underbalanced pressure after equipment installations":
    - Production wellhead and lubricator
    - Monitoring of the wellhead pressure when:
      - Firing
      - Pulling out
- **Further precautions when loading, starting to run in and concluding pulling out:**
  - All radio communications cut-off (depending on the type of fire system)
  - Non-essential personnel out of the way
  - Nobody in the line of fire (if possible)
  - Extra care when pulling out if misfire

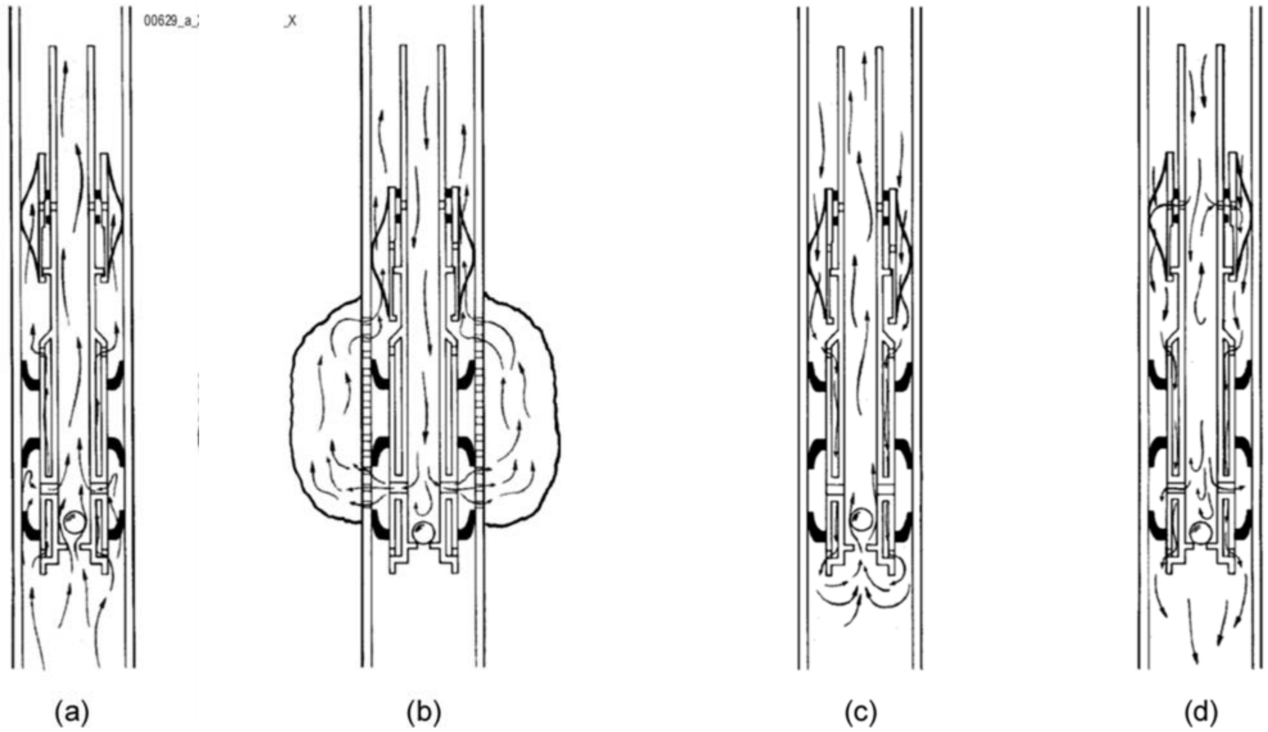
Other operating points

- **Perforation depth adjustment:**
  - By reference to logs
- **Cleaning the perforations:**
  - Well clearing
  - Back surging*
  - Washing tool*
  - Acid washing

Back surging



Washing tool



Running in | **Washing perforations** | **Reversing off bottom** | **Coming out of hole**

Other operating points (cont.)

- **Monitoring the result:**
  - Flow rate measurement (test separator)
  - Well testing
  - Production logging

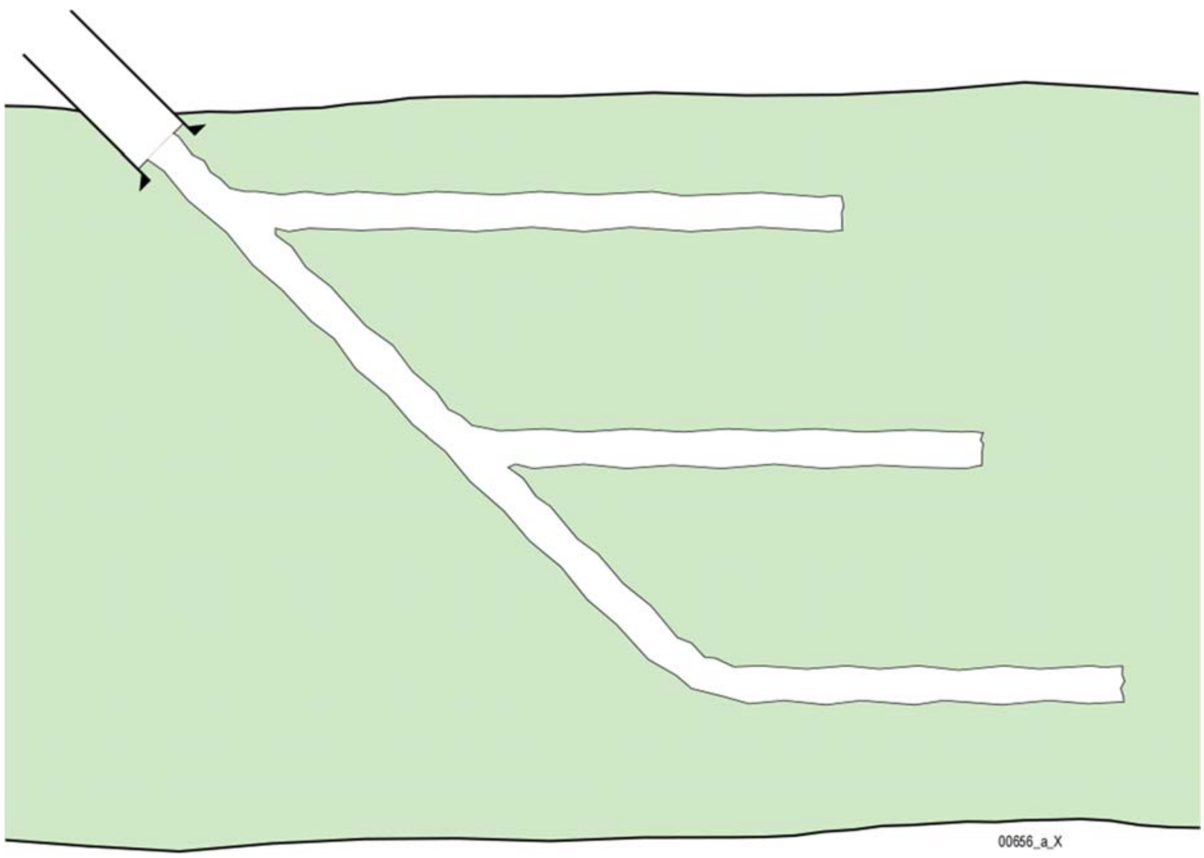
Notes

The special case of horizontal wells

Advantages in producing reservoirs

- **For a low permeability formation:**
  - Advantages in comparison with a hydraulic frac:
    - Horizontal extension
    - Frac residual permeability
    - Control of the orientation
    - No problem of vertical extension (when interface)
    - $\Rightarrow$ Improved productivity
  - Drawbacks if:
    - Thick reservoir
    - Low vertical/horizontal permeability ratio
    - But multidrains*

Single layer and direction multidrains well



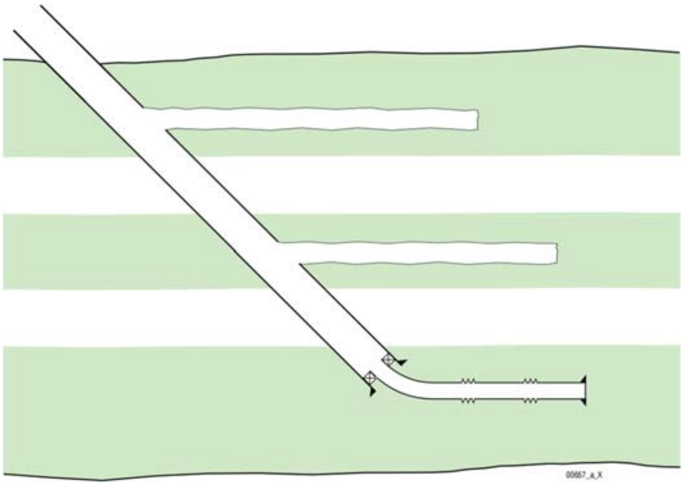
Advantages in producing reservoirs

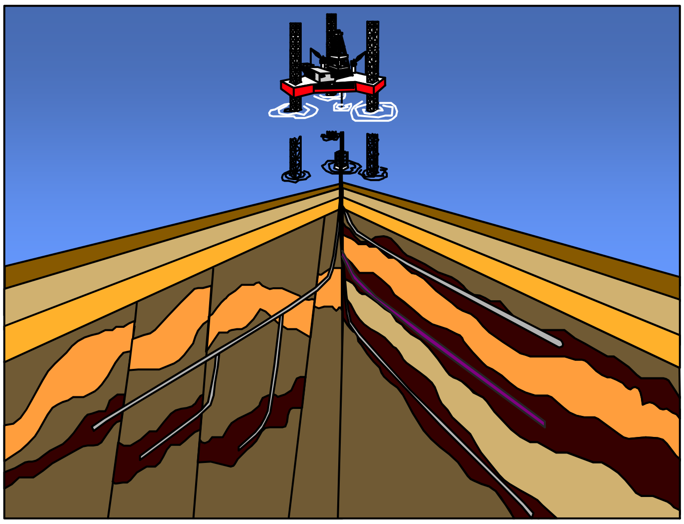
- **For a thin formation:**
  - Horizontal drain length versus vertical drain length
- **For a plugged formation:**
  - (Secondary consequence)
- **With regard to turbulence effect**
- **With regard to critical flowrate (coning):**
  - Productivity index
  - Drain/interface position

Advantages in producing reservoirs

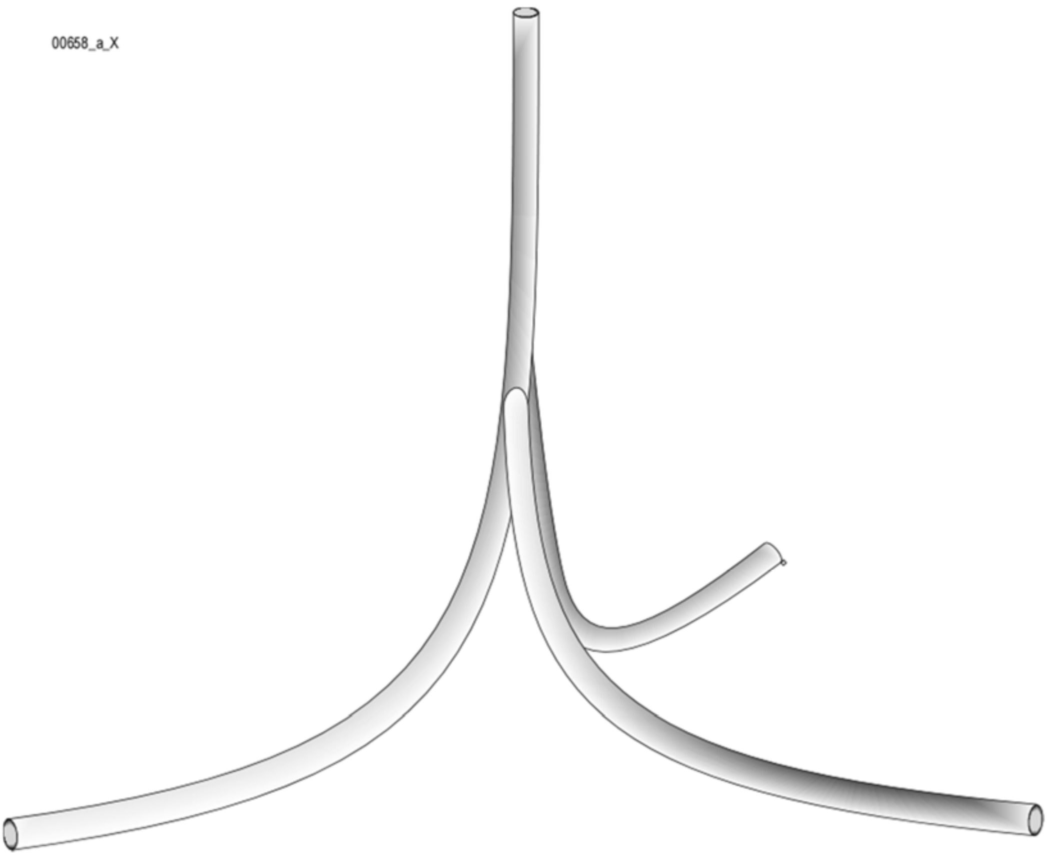
- **For an insufficiently consolidated formation:**
  - Fluid velocity
  - Accumulation capacity
  - Screen plugging
- **For a multilayer reservoir*:**
- **For a naturally fractured, heterogeneous formation, etc.:**
  - Fracture interception, etc.
- **With regard to recovery:**
  - Drainage area*
  - Secondary recovery:
    - Injection capacity
    - Injection distribution

Multilayer multidrain well





Single layer and multidirectional multidrain well



Advantages in producing reservoirs

- **Generally speaking, if appropriate conditions:**
  - Faster recovery rate

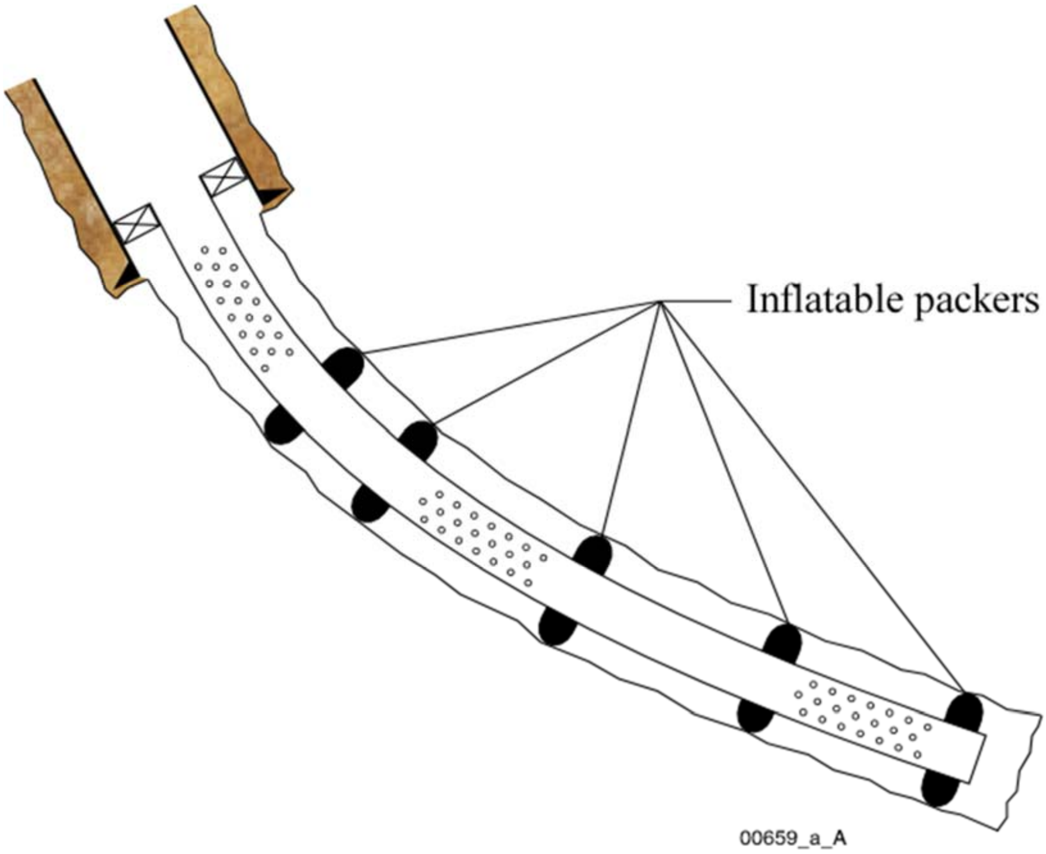
  and/or
  - Fewer wells

  and/or
  - Help to solve some production problems
    - Lower differential pressure (P_R - P_{BH})
    - Increased recovery rate

Problems specific to the payzone-borehole connection

- **Configuration:**
  - Basic configurations:
    - Open hole
    - Pre-perforated liner
    - Partially pre-perforated liner + inflatable packers*
    - Cemented liner then perforating
  - Configuration selection:
    - Function of:
      - Initial conditions
      - Parameters evolution

Partially pre-perforated liner + inflatable packers



Problems specific to the payzone-borehole connection (cont.)

- **Liner running in:**
  - Enough but not too much centralizers
- **Liner cementing (if necessary):**
  - Usual precautions

  and:
  - Cleaning of the horizontal part
  - Enough centralizers
  - Prevention of the water migration from the slurry
- **Perforating:**
  - High cost
  - Methods: cf logging in horizontal hole
  - If TCP are used:
    - Guns have to be pulled out after fire
    - Mind the curve radius
  - Do not get stuck

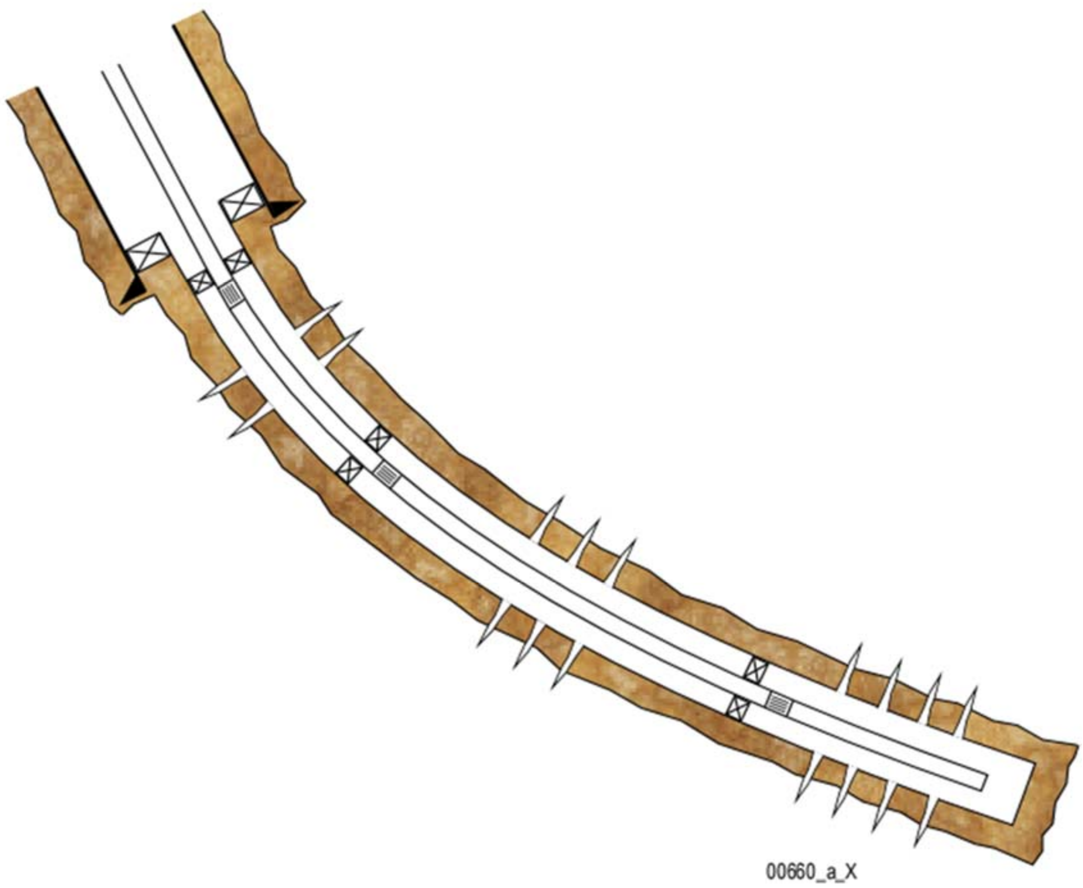
Problems specific to the payzone-borehole connection (cont.)

- **Sand control:**
  - Higher critical flowrate
  - Screens alone

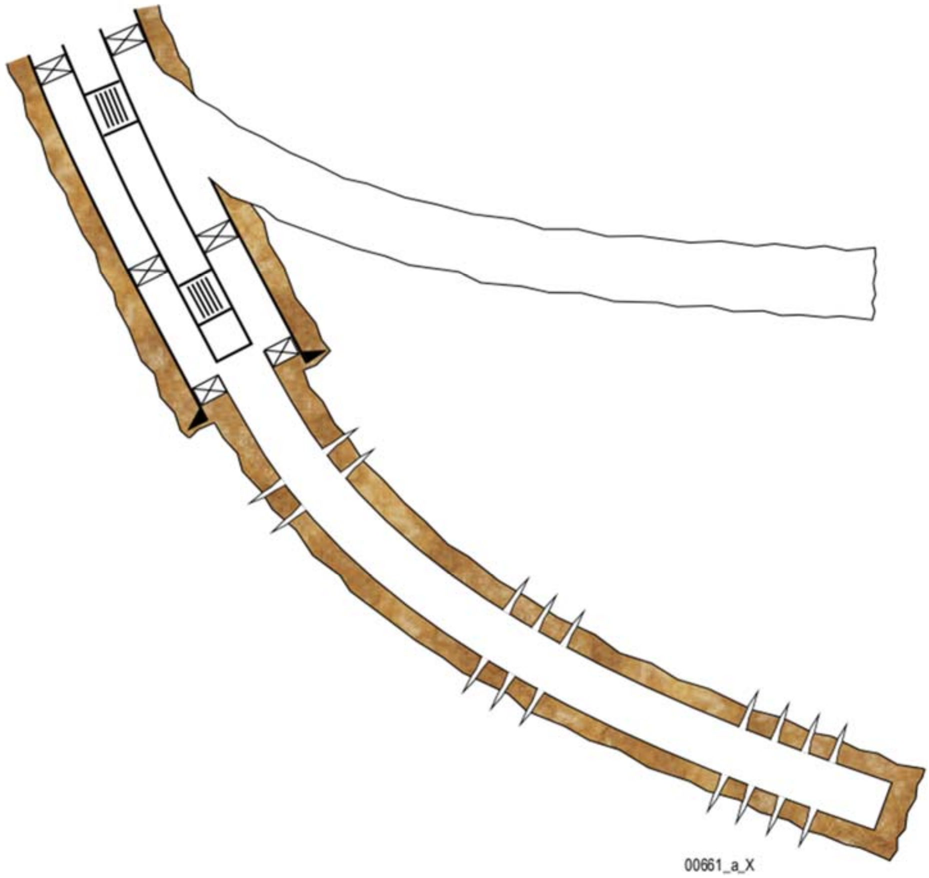
  or

  - Gravel packing (with specific screens or implementation techniques)
  - Consolidation not really applicable
- **Stimulation:**
  - Be careful with selectivity problems
- **Production string configuration:**
  - Usually, single tubing string completion* (without or with zones selection) Possibly, multiple (tubing string) completion*

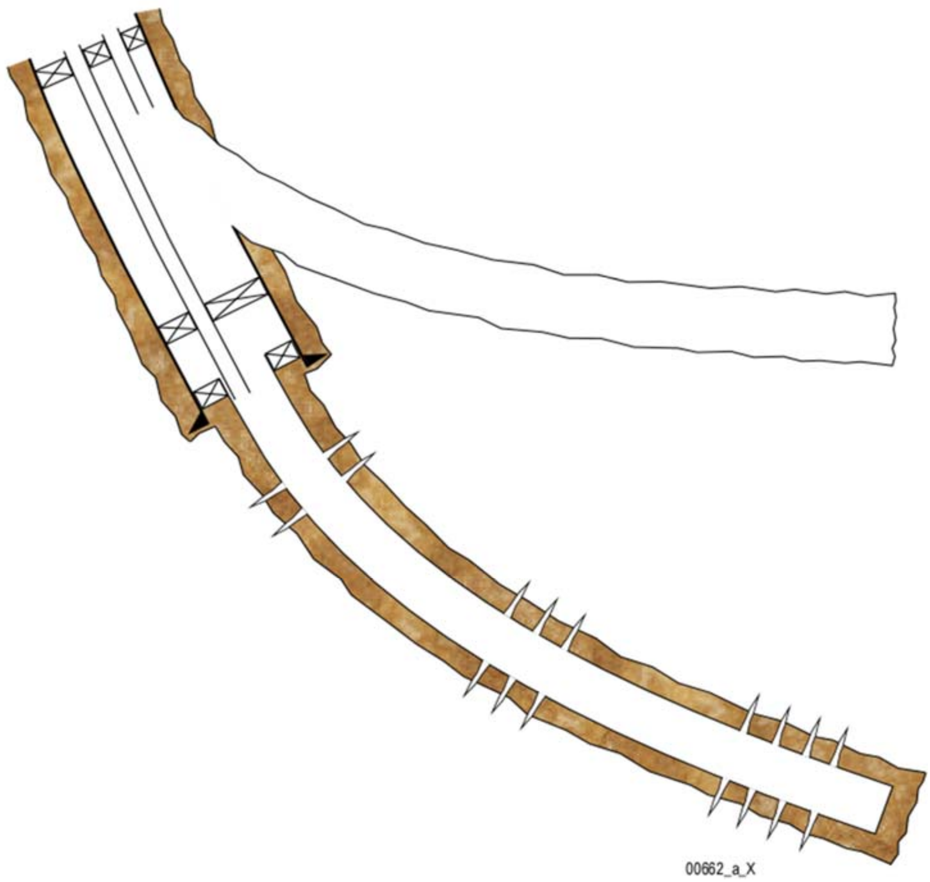
Selective completion in an horizontal single drain well



Selective completion in a multidrain well



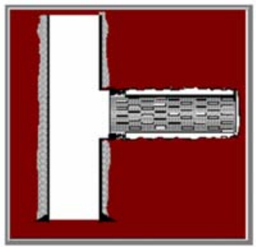
Dual tubing string completion in a multidrain well



Multi lateral well: TAML(*) junction classification

- **“A multi-lateral well is one in which there is more than one horizontal or near horizontal lateral well drilled from a single main bore and connected back to that main bore.”*TAML 1997***
  - Level 1:
    - Open / unsupported junction
      (Barefoot mother-bore & lateral bore
      or with slotted liner in either bore)

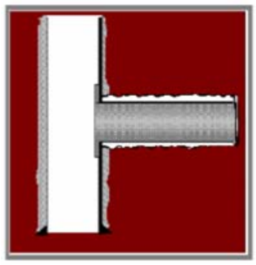
  - Level 2:
    - Mother bore cased and cemented
    - Lateral bore open
      (Lateral bore either barefoot
      or with slotted liner in openhole)



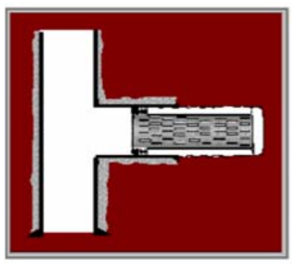
(*): TAML group (North Sea) : Technology Advanced Multi-Lateral group

Multi lateral well: TAML(*) junction classification (cont.)

- Level 3:
  - Mother bore cased and cemented
  - Lateral bore cased but not cemented
    (Lateral liner anchored to mother-bore with
    a liner hanger but not cemented)



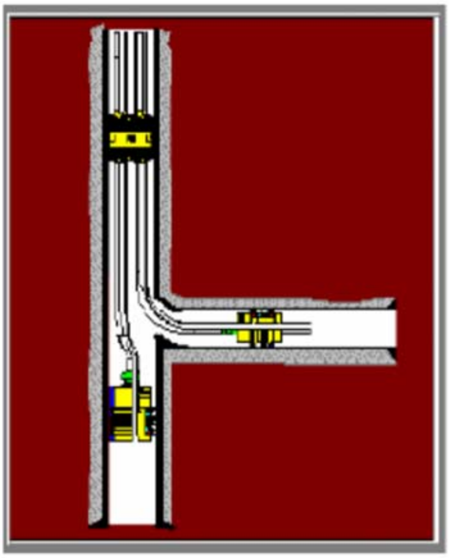
- Level 4:
  - Mother bore cased and cemented
  - Lateral bore cased and cemented
    (Both bore <u>cemented at the junction</u>
    but no pressure integrity: cement not
    considered as a sealing mechanism)



(*): TAML group (North Sea) : Technology Advanced Multi-Lateral group

Multi lateral well: TAML(*) junction classification (cont.)

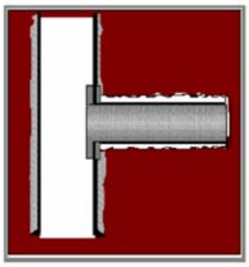
- Level 5:
  - Pressure integrity at the junction achieved with the completion
    (Cement not acceptable as not considered as a sealing mechanism)



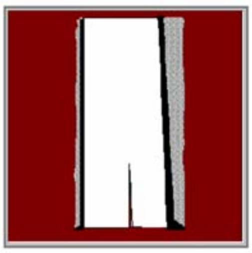
(*): TAML group (North Sea) : Technology Advanced Multi-Lateral group

Multi lateral well: TAML(*) junction classification (cont.)

- Level 6:
  - Integral junction : pressure integrity at the junction achieved with the casings
    (Cement not acceptable as not considered as a sealing mechanism)



- Level 6S:
  - Integral junction : downhole splitter with pressure integrity
    (Large main bore with two or more smaller lateral bores)



(*): TAML group (North Sea) : Technology Advanced Multi-Lateral group

Notes